BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

TECHNICAL CONFERENCE ON :

RESOURCE ADEQUACY :

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Commission Meeting Room 2nd Floor

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Tuesday, November 19, 2002

The above-entitled matter came on for technical conference, pursuant to notice, at 9:30 a.m., Kevin Kelly, presiding.

APPEARANCES:

REGINA M. CARRADO, Regulatory Specialist, Exelon Corporation, Exelon Generation, LLC

DAN GRIFFITHS, Senior Public Policy Research Analyst, Pennsylvania Office of Consumer Advocates

DAVID LaPLANTE, Vice President, Markets Development, ISO New England Inc.

RONALD G. LUKAS, Senior Vice President, KeySpan Energy Supply, LLC

KAREN KRUG O'NEILL, Vice President, New Markets, Green Mountain Energy

MARK REEDER, Chief, Regulatory Economics, New York Public Service Commission

MICHAEL ALCANTAR, Attorney, Alcantar & Kahl LLP, on behalf of the Cogeneration Association of California (CAC) and the Energy Producers and Users Coalition (EPUC)

KIERAN CONNOLLY, Public Utilities Specialist, Bonneville Power Administration

PETER EVANS, President, New Power Technology, on behalf of the Silicon Valley Manufacturing Group (via telephone)

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APPEARANCES (CONTINUED):

KELLAN L. FLUCKIGER, Senior Advisor to the Chair and CEO, California Consumer Power and Conservation Financing Authority

JOHN MEYER, Vice President of Asset Commercialization, Reliant Resources

CHARLES REINHOLD, WestConnect RTO Project Manager, Electric Resource Strategies

GARY STERN, Director of Market Monitoring and Analysis, Southern California Edison Company

JAMES CALDWELL, Policy Director, American Wind Energy Association

WILLIAM F. HALL, III, Senior Vice President, Energy Policy & Strategy, Duke Energy Corporation

WILLIAM J. HEAD, Chief Operating Officer, MAPPCOR, representing the Mid-Continent Area Power Pool

STEPHEN L. HUNTOON, Senior Director & Regulatory Counsel, Dynegy Power Marketing, Inc.

SAM RANDAZOO, Partner, McNees, Wallace & Nurick, LLC, on behalf of Ohio Industrial Consumers

RICK RILEY, Director, Transmission Policy, Entergy Services, Inc. on behalf of SeTrans Sponsors

RAYMOND J. WAHLE, P.E., Director, Power Supply and Operations, Missouri River Energy Services

-- continued --

APPEARANCES (CONTINUED):

THE HONORABLE THOMAS WELCH, Chairman, Maine Public Utilities Commission

THE HONORABLE ROBERT B. NELSON, Commissioner, Michigan Public Service Commission

RICHARD CAMPBELL, Director, Energy & Technology, American Forest & Paper Association

DAVID R. NEVIUS, Vice President, North American Electric Reliability Council

DR. CRAIG ROACH, Partner, Boston Pacific Company, Inc., on behalf of the Electric Power Supply Association (EPSA)

ROY SHANKER, Consultant and Participant of the Northeast Joint Capacity Adequacy Group

S. LYNN SUTCLIFFE, Chairman, Praxair Energy Solutions, on behalf of the National Association of Energy Service Companies (NAESCO)

DAVID M. VELAZQUEZ, Vice President, Business Planning, Conectiv Energy Supply Inc., on behalf of The Edison Electric Institute (EEI) and the Alliance of Energy Suppliers

PROCEEDINGS

(9:30 a.m.)

MR. KELLY: I'd like to ask the panelists to take their seats so that we can get started. Good morning again. Please take your seats, we'd like to get started. We'd like to ask the panelists to sit down.

(Pause.)

I see that Regina Corrado is ready to go. Dan Griffiths is missing in action. Karen Krug is taking her seat. I see Mark Reeder approaching the forum. David LaPlante; is David here?

VOICE: Yes, he's here.

MR. KELLY: Ah, David, please sit down, thank you. And there's a little bit of congestion in the isles to be cleared and we'll be ready to get going.

(Pause.)

Well, good morning again. My name is Kevin Kelly, and I'm with FERC's Office of Markets, Tariffs, and Rates. In addition to the Commissioners who will be participating today, there is with me from the FERC Staff, David Mead, Dan Larcamp, Derrick Bandera, all with the Office of Markets, Tariffs, and Rates; Rob Gramlich, Electricity Advisory to Chairman Wood, Alice Fernandez, and Mark Hegerle, also from Markets, Tariffs, and Rates, and Dr. Ed Meyers, State Relations. Good morning to all.

The subject of today's conference is the part of the Commission's proposed SMD rule dealing with resource adequacy. The Commission made its proposal to provide a minimum framework to ensure that the level of regional resources planned for the future is adequate for reliable transmission operation and energy supply.

This proposal is intended to complement and not replace existing statutory state and regional resource adequacy provisions. Our proposed resource adequacy provision is designed to satisfy three criteria:

First, the provision is intended to be forward-looking; that is, we should begin developing resources in time to have the resources available in the region when they are needed, to avoid a period of shortage.

Second, the resource adequacy provision should treat all resources equally, including resources for reducing demand.

Third, because the nation has states with retail access and without retail access, the provision should work well in both types of states. Today we hope to hear how well our proposal meets these criteria, and, more important, we hope to hear alternative proposals for meeting these three criteria from our panelists.

Our purpose today is to have an exchange of views about the best way to design a resource adequacy requirement, and we want to explore whether the best way may be different from region to another.

We expect to learn a lot from the panelists' comments today, and we also expect today's discussion will help all who listen to this conference to file better-informed comments on January the 10th. With the diversity of views among panelists, it will be interesting to see if the beginnings of a consensus view starts to emerge.

In our many outreach meetings, we've been struck by two trends: First, in regions that are made up mostly of states with retail choice programs, there have been many comments calling for a requirement with stronger enforcement than what the Commission proposed.

Second, in regions that are made up mostly of states without retail choice programs, there have been many comments calling for a less intrusive federal role. Because most regions with retail choice have at least one state that does not, and most regions without retail choice have at least one state with retail choice.

We're especially interested today in discussing with the panelists, how these apparently conflicting comments can be reconciled.

I wanted to give the panelists for the whole day, a heads up on a question we intend to pursue with you as you make your alternative proposals. We have received from the panelists, many very good alternative proposals, but for many of them, unfortunately, the final page was missing. It must have been either a fax or an e-mail glitch, and that is, what should the final rule say about your proposal?

And I thought of five things it could say, and maybe today we can explore how to fill in that missing page. One of the things you could say is, well, my idea is an interesting idea, but it's too experimental yet to be a requirement.

A second thing you could say is, FERC should allow in its final rule, regional discretion so that I can try to persuade others in my region to try my alternative. But keep the FERC NOPR proposal as a default mechanism, if my region cannot agree.

The third thing you might be saying about your proposal is, FERC should require my region to use my alternative proposal. A fourth thing you might be saying is, well, FERC should allow regional choice and let each region do what it wants to, but substitute my proposal for the NOPR proposal as the default proposal, if a region fails to reach an agreement.

And the fifth and strongest thing you could say is, my idea is really good and ought to be imposed on all regions as the FERC requirement. So, maybe as we get into the discussion today, you can clarify, you know, what the last page of your proposal ought to be saying in that regard.

And I would urge those filing comments on January 10th with alternative proposals, which we welcome, to say what the final rule should say about your proposal.

Before we begin, let me just go over a few procedural items. First, I want to say that many people requested an opportunity to sit on the panels today, and we were able to accommodate only some.

However, we would like input from all who have something to say on resource adequacy. So I encourage you, if you haven't already, to submit concrete proposals in response to what you hear today. Those that are submitted will be made available on our web page at www.ferc.gov.

Second, the panels are not organized by subject, so that each panel is free to explore the full range of resource adequacy issues, such as those identified in the notice of this conference. In that regard, we request all panelists, not only to discuss possible improvements to the SMD proposal, but also to offer concrete alternative proposals.

We want to reserve as much panel time as possible for discussion, so we've asked panelists to take no more than three minutes to give an overview of their position on these issues.

I would ask this panel and the later panels to try to limit the time describing your company, and spend as much of your three minutes as possible, setting out your ideas about resource adequacy for panel discussion. Please remember to turn your microphone on when you are speaking, and to speak directly into the mike. We have a lot of FERC staff throughout the building, listening to this in the Internet and other people around the country listening in, too.

After these opening statements, I'd ask that if you want to be recognized to speak, you turn your name card up like this. So, let us get started.

Our first speaker is Regina Corrado, Regulatory Specialist of Exelon Corporation, representing Exelon Generation, LLC. Please begin.

MS. CORRADO: Thank you. Good morning. First off, I'd like to thank the Commission for this chance to speak on behalf of Exelon. I wanted to start out by saying that Exelon Corporation, as a T&D company, a load-server, a generator, and a wholesale marketer, has looked at the subject of resource adequacy from many different perspectives.

We strongly believe that the Commission, as reflected in the NOPR, has properly understood and articulated the need for a forward resource reserve requirement. We believe the SMD proposal on resource adequacy includes several positive fundamental features. These are:

Number one, state involvement in setting the reserve requirement; two, a longer planning horizon to promote resource competition; three, equal opportunity for both generators and demand-side resources; and, number four, a deliverability requirement, so the energy can make it to the load.

However, despite these positive attributes, Exelon believes the specific mechanics in the SMD proposal will not succeed in the retail environment. While it is recognized that longer planning horizons are necessary, individual load-serving entities in regions with retail choice cannot predict far beyond the operating year, what their load needs will be.

What can be and has been reasonably forecasted is the load for the total region. As a solution, Exelon advocates an alternative called the Forward Resource Procurement Method or FRPM. FRPM mirrors the work of the Joint Capacity Adequacy Group which was formed in the Northeast, also known as JCAG, which I believe Mr. LaPlante will further elaborate on.

Before I proceed, there is one clarification I need to make. I have already used the acronyms FRPM and

JCAG to refer to the same process. You may also hear the term, centralized resource market, CRM, or resource adequacy model, RAM. FRPM, JCAG, CRM and RAM, they are all the same. If this proposal is going to succeed, we ned to come up with a single name.

Now, I'd like to explain the basic elements of the FRPM method: First, the ITP would determine the total regional forecasts for a future planning year -- three years out -- and then determine the amount of resources required to meet that load need.

The ITP would establish qualification criteria for both generation and demand-side resources. Second, the ITP would run an auction to identify which resources would satisfy the total regional requirements.

This requirement will be satisfied through the auction at the lowest clearing price. The ITP would not take ownership in these resources, however, it would act as a clearing house, matching the resources to the LSE's needs, if and when they need it.

The ITP then charges all LSUs a the auction clearing price, based on the actual load they are serving. Bilateral contracts or self-supply, also called opting out of the auction, is accommodated, however, even opt-out resources must be subject to the same criteria that auction resources are subjected to.

There are no deficiency penalties for LSUs under this method. Their needs are inherently met because the total regional requirement is met.

There are, however, penalties for generation owners who commit to supplying a certain amount of resources, but do not supply them in the operating year.

In closing, it's important to note that both the SMD and the FRPM proposals use a planning year sufficiently far in the future to allow sufficient time for new entrants to build needed resources and for the development of demand side programs.

In addition, and to reiterate, the FRPM method facilitates retail choice by first making sure the region, as a whole, has enough resources to meet the future load needs and then, by charging a competitively-set price to LSEs, who may not have sufficient resources under contract to serve those needs.

The price certainty that this provides to LSEs will facilitate state approved retail choice programs. Exelon firmly believes the forward resource procurement method is the best solution for ensuring that the future load needs can be met, and we look forward to working with all relevant parties to further this proposal. I thank you for your time.

MR. KELLY: Our next speaker is Dan Griffiths, Senior Public Policy Research Analyst with the Pennsylvania Office of Consumer Advocates.

MR. GRIFFITHS: Thank you. The Pennsylvania Office of Consumer Advocates thanks you for inviting us to participate in today's panel.

We agree that energy markets alone are not sufficient to protect consumers and assure reliable service. Our analysis convinces us that the Commission's long-term adequacy proposal is inconsistent with the needs of regions with retail choice.

We are also concerned with other proposals within the Northeast region, that they will result in unnecessary costs to consumers. Our alterative proposal seeks to address several critical issues:

It satisfies long-term resource adequacy needs; it provides for resource adequacy at a reasonable cost; it assures that resources will be available by giving the ITP the last-resort backstop responsibility.

The regional capacity market supports the entry of new competitive suppliers, and capacity payments must take into account, the revenues which generators receive from energy and ancillary services.

Our proposal contains five action items: A capacity requirement based on a one-day-in-ten-years loss of load probability.

Second, the ITP holds an auction every six months for a six-month period 18 months in the future.

Planned generation demand resources or transmission projects may bid into the auction, assuming that nonperformance penalties will apply.

Third, all offers are subject to bid limits or caps. The bid limits should reflect an assessment of the carrying costs of new peaking capacity, minus expected energy and ancillary service revenues.

This reflects our conclusion that revenues in those energy markets which clear at the marginal offer, are above actual cost for many generators.

Fourth, a periodic balancing mechanism based on the auction price for the period. This allows a load-serving entity to know the capacity price before it acquires new load.

Finally, if the ITP determines markets have failed to provide needed resources, it or a special purpose entity would competitively bid for the construction of least-cost resources.

In conclusion, the acquisition of capacity is best fulfilled through a combination of RTO-administered auctions and bilateral contracts.

This should be done through a mandatory semiannual auction with a ceiling prices which mitigates supplier market power using market-based pricing.

Finally, there must be a backstop mechanism to assure that there will be resources. Thank you.

MR. KELLY: Thank you. Next we have David LaPlante, Vice President of Markets Development, ISO New England.

MR. LaPLANTE: Good morning. Thanks for the opportunity to discuss this important issue. Assuring resource adequacy is a difficult and important public policy issue.

The Commission's NOPR proposes a resource adequacy approach that recognizes that assuring a reliable supply of electricity at a reasonable price is essential.

By making resource adequacy a requirement, the Commission is imposing a significant responsibility on ITPs and itself to assure that the requirement is being met and functions properly.

Even a requirement that relies primarily on bilateral agreements is likely to engender questions about the terms of those arrangements, particularly in times of short supply.

These issues will inevitably end up before the Commission. The Northeastern power pools have traditionally relied on an installed capacity or an ICAP mechanism to meet resource adequacy requirements to ensure reliability of the bulk power system.

Recognizing that the ICAP markets have not been performing their functions as well as possible or desired, and cognizant of the need to resolve seams issues, ISO New England, PJM, the New York ISO and all our market participants formed the Joint Capacity Adequacy Group and began meeting in December of 2001 to deal with and to create a single ICAP, at that time, market design.

Taking the lead from the Commission Staff's ICAP paper in late December, JCAG focused on changing the ICAP mechanism from its current near-term focus to a forward-looking requirement.

A large degree of generation divestiture and retail competition in the Northeast also made it necessary for the new mechanism to work in an environment where responsibility for serving load could vary as often as monthly.

The JCAG proposal has received support from all of the Northeastern ISOs and their stakeholders. We are currently exploring several ways of putting the proposal before the Commission, and hope to eventually receive Commission support to implement the proposal throughout the Northeast region.

In the proposal, each ISO and RTO prepares a forecast of future market resource requirements for its region for two to five years into the future. The timeframe is still under discussion.

Each ISO and RTO would then hold separate but coordinated auctions to procure sufficient resources to meet the forecasted need for that year.

The auction design would support and encourage the use of bilateral agreements for load-serving entities to meet their obligations. Generation and demand resources and the use of merchant transmission is also under discussion, and would participate in the auction.

To assure that capacity is not withheld from the auction, a must-offer requirement is being considered. Whether that would require everyone to bid in or whether you could opt out with contracts with differences, is an issue.

The auction would result in a clearing price for capacity a future year. That price would be paid by load-serving entities in the future year to all capacity that clears in the auction.

In this way, price certainty would be provided to enable LSEs to plan for their future obligations, and to encourage the development of new resources. The proposal would also allow each area to assure capacity is deliverable, consistent with the respective regional reliability practices.

The proposal assumes that sufficient resources will be bid into the auction to meet the forecasted need. A key issue still under discussion is the mechanism by which delivery of capacity in the future is assured.

A severe penalty charge of two or three times the cost of a peaking unit is under consideration as a possible penalty, together with a requirement to provide financial security of some type at the time of the auction.

We feel the JCAG proposals is an innovative evolution of the existing ICAP mechanisms into a resource adequacy solution for the Northeast region that meets the spirit and policy objectives of the NOPR. Thank you.

MR. KELLY: Thank you. Our next speaker is Ronald J. Lukas, Senior Vice President, Keyspan Energy Supply, LLC.

MR. LUKAS: Good morning. Keyspan owns about 2200 megawatts or 20 percent of the in-city capacity in the New York City load pocket. We're currently building 250 megawatts of new capacity in the City, scheduled to be online in the fourth quarter of 2003.

I am personally responsible for our electric and gas retail choice programs. We have a corporate strategy committed to distributed generation, and I'm also an electric wholesale policy co-chair for the National Energy Marketers Association.

Keyspan strongly supports a resource adequacy requirement designed under the following concepts, to ensure both reliability and a reasonable chance for developers to achieve a risk-adjusted rate of return on their investment.

With that in mind, I would like to comment that you just can't cap the up side when there are shortages, so generators just eat the down side when the market is even slightly long, a problem we have in the current design of the capacity market with the New York ISO.

To avoid this, we see a market that has a long-term planning horizon consistent with the lead time to build new plants. It should include some of the favorable aspects of gas pipeline precedent agreements that include milestones that must be met in order to continue to be valid.

It recognizes local constraints. It has regulatory certainty for both supply and demand, and a possible practical solution could be the development of a demand curve, which is something that's being discussed at the New York ISO.

A very important point is that it eliminates the effect of lumpiness where generators who build create excesses that diminish auction prices close to zero. Even slight excesses in New York have diminished the price. Or, when a unit is retired, it will prevent prices from spiking.

It recognizes the annual nature of the costs incurred to maintain plants. It encourages a long-term bilateral market.

In that regard, we see the resource adequacy as encouraging power purchase agreements, and also because you might have power purchase agreements under such a proposal, it would help mitigate market power.

Finally, I would like to note that the resource adequacy requirement can't be looked at in isolation from energy mitigation. Our experience shows that to the extent that mitigation measures have been put in place, that limits scarcity pricing in conjunction with new capacity prices that do not recover replacement costs.

You have a lethal combination that makes it virtually impossible to justify investing in new generation. Simply put, under these circumstances, the dollar inflows from the market will not exceed the costs incurred to finance and operate the plants. Thank you.

MR. KELLY: Thank you. Next, Karen Krug O'Neill, Vice President, New Markets, Green Mountain Energy.

MS. KRUG-O'NEILL: Good morning. I appreciate the opportunity to provide you today with a competitive LSE's perspective on the resource adequacy mechanisms proposed by FERC and other stakeholders.

Let me start by saying that we agree with Professor Hogan's recently filed comments in this docket, to the effect that if FERC were to let the ancillary energy markets envisioned in the SMD develop and operate, we might not need to address resource adequacy.

However, if FERC must continue to develop and implement a separate mechanism for assuring resource adequacy, there are essential features that should be incorporated.

Green Mountain's objectives with respect to resource adequacy mechanisms are: One, that it maximize the value we all want -- adequate resources at a minimum cost;

Two, that it interfere as little as possible with the efficient functioning of markets; And, three, that it incorporate a mechanism for recovering the costs of resource adequacy from all customers, in a competitively-neutral manner.

I want to elaborate on this last point, because I think that FERC's resource adequacy requirement and several of the other proposals proposed by other stakeholders, placed the full burden of assuring resource adequacy on LSEs, based on an assumption that LSEs can and will front the associated costs and pass them on to ultimate customers.

It's important to understand, however, that Green Mountain and other competitive LSEs are unlike incumbent LSEs, in that, one, we don't have established and stable customer bases; we do not have a regulatory process to defer or pass on increased wholesale cost to retail customers.

We frequently don't own generation, and we must rely on our own credit rather than the creditworthiness of a regulated utility.

In addition, competitive LSEs may find it difficult or impossible to pass on increased costs of assuring resource adequacy because in many jurisdictions, we compete against capped utility rates.

These circumstances mean that many competitive LSEs are ill-equipped to deal with the increased costs and risks imposed by FERC's proposed RAR and alternative proposals that place the full cost of resource adequacy on LSEs.

In that regard, it should be noted that the competitive retail market, as a whole, currently serves over 36,000 megawatts of load in this country. Therefore the impact on our sector of the industry needs to and to date has only marginally been considered in designing an appropriate resource adequacy mechanism.

The resource adequacy model that Green Mountain supports avoids the problems I've described for competitive LSEs while assuring resource adequacy and supporting the continued development of competitive wholesale markets. It's key features include the following:

The ITP determines on an annual basis whether there's a gap between desired resource adequacy level and the resources available in the region.

If a gap exists, the ITP holds an auction to determine what incentive is necessary in order to encourage the develop of new resources for availability in the planning year.

New and repowered power plants demand resources and transmission assets would all be qualified to participate. And the cost of the new resource payments would be paid for by all customers in the region as a public good charge.

Now we recognize that a controversial aspect of this proposal is that it doesn't offer incentive payments to existing resources, and many generators argue that revenues are needed to cover costs of those resources that aren't recoverable today in energy and ancillary markets with market mitigation.

We agree that too much mitigation poses a problem, and urge that it be utilized only to target specific instances of market power.

If mitigation were limited in this way, we believe markets could work effectively to reward existing generation and we'd avoid making payments to existing generation that are not needed in many instances to cover costs, don't ensure the development of new resources, and prevent the entry of new or more efficient technologies.

We believe that our proposal offers several key advantages over competing proposals. One, it is assures that sufficient new resources will enter the market to satisfy customer demand and it does so at the lowest cost to consumers.

Liquidity of wholesale markets will be maintained and market power will not be perpetuated. And retail competition won't be adversely impacted in restructured markets.

Thank you.

MR. KELLY: Thank you.

Our final panelist is Mark Reeder, Chief, Regulatory Economics, New York Public Service Commission.

MR. REEDER: Thank you, and thank you for giving me the opportunity to come here today and share my views and the views of the Department of Public Service Staff.

For any product or service, spot markets are very important--always. So too, spot markets for capacity are very important. Currently, spot markets for capacity are broken. They don't work. And broken spot markets tend to back up and damage forward markets.

The New York PSE Staff has put forward a proposal to fix the spot markets for capacity that are run by ITPs. In so doing, we believe that forward markets will also be substantially fixed.

There are two major, well-known problems with the current capacity markets run by he ISOs in the Northeast.

First, capacity market prices are much too volatile. They suffer from extreme boom or bust phenomenon. This undermines one of the key goals of the market which is to attract new entry.

Second, the existing market design leaves it quite vulnerable to market power and it is most vulnerable when the amount of capacity is about equal to the amount that's required. This is bad for buyers and it is bad for the goal of promoting competitive behavior.

The New York PSE Staff has put forward a market design proposal which we call the Resource Adequacy Assurance Mechanism but the name isn't catchy and most people refer to it as the demand curve approach.

The proposed approach repairs the spot market. It virtually eliminates the boom or bust phenomenon. And in doing so, it also mitigates the market power threat.

How does the proposal work? It uses a centralized procurement process run by the ITP. The key to it is that it calls for ITP to procure more than the minimum required amount of capacity whenever such additional capacity is available at reasonably modest prices.

The ITP's willingness to pay for additional capacity is set forth in the form of a demand curve, hence the name, to buy capacity. The demand curve is established in advance and signalled to all market participants.

According to this demand curve, the price the ITP is willing to pay for capacity declines gradually as the quantity of capacity that's available increases.

Why is such an approach advisable?

Well, first of all it makes sense. The marginal value to the system of additional capacity beyond the required minimum amount is not zero. But the current market design implies that it is zero.

Rather, buying additional amounts has a positive value and that value declines as the amount of capacity increases. But the main reason for adopting a demand curve approach is that the results that it produces addresses the problems that we see.

Price volatility is greatly reduced. The future spot prices therefore become much more predictable. This feature helps new entry and helps forward markets.

Furthermore, the gradual feature of the demand curve is designed specifically to alter the calculus of an attempt at market power making such a strategy unprofitable and therefore unlikely to occur.

To sum up, a well-functioning spot market is a powerful force in an overall market, and it acts as a cornerstone for the market's other components such sa forward markets to work well.

Thank you.

MR. KELLY: Thank you. Alice Fernandez, do you want to begin.

MS. FERNANDEZ: Yes. I think first maybe I'd like to sort of clarify sort of where the differences are among the panelists.

I took it from the presentations that all of you are supporting some form of centralized market for capacity. Is that correct? And it seemed like the major difference was Ms. O'Neill wanted that market to focus just on new entrants.

MS. O'NEILL: Correct, and actually the auction is not for capacity itself but for the incentive that's necessary to bring new capacity on line.

MS. FERNANDEZ: Okay. Whereas all of the other proposals basically focus on new entrants could participate as well as existing? Is that--

MR. LUKAS: We support that, yes.

MS. FERNANDEZ: And in terms of the various acronyms that we had, because everybody had one and we also had the demand curve for reserves, are they all fairly similar in sort of the basic concept? It seems like it's more of the details of exactly how the centralized market would work?

MR. LUKAS: I would like to comment. I think we heard two different approaches. We heard discussion of an auction and I think Mark--and I will probably regret supporting a lot of the things Mark said--but it made a lot of very good points. There's a spot auction but then there's the demand curve type approach which is longer term in nature and we would support -- we have learned from experience.

We've committed to building a new plant inside New York City. We didn't envision the drop in capacity prices under this spot auction method that we have in New York now, and I think that the demand curve is a good remedy.

So I think we need to distinguish the different proposals of the people who support just the spot auction versus a longer term solution similar to the demand curve which we think, as a practical approach, works.

MS. CARRADO: I just want to say that we look at the demand curve and we think it has merit, but we look at that as an enhancement to the central auction process. So we list some core fundamentals that we believe are necessary. The demand curve, you know, has merit and would be nice but we see that as an enhancement to the process.

And the other difference may be in the central auction. We want to see the total load for the region procured in that auction. Where other proposals look at the net load, you take off the bilaterals and the self-supply and just run the auction for the net load. So that's a difference, I think, in some of the proposals out there.

MS. FERNANDEZ: Okay, but I thought under your proposal bilaterals you could still get credit for it?

MS. CARRADO: You get credit for them. They are also--all the resources are bid into the auction. If it's a bilateral, it could be done as a contract for differences against the auction clearing price.

MS. FERNANDEZ: Okay, whereas with some of the other proposals if you had a bilateral, you wouldn't have to participate in the auction.

MS. CARRADO: Exactly.

MR. GRIFFITHS: I guess I look at this, we are here because folks spent too much on capacity in decades gone by. And reliability is certainly the sine quo non for us. But we are concerned about a system which will establish such certainty that we will end up with high-priced capacity again.

MR. KELLY: Mr. Reeder?

MR. REEDER: I just want to comment on the statement about the bilaterals being involved in the auction.

In our proposal, the centralized spot market with a demand curve, the bilaterals bid theirs in also. So there's no difference three.

MS. FERNANDEZ: So you would be closer to the contract for differences?

MR. REEDER: Yes, in terms of the role of bilaterals.

For example, all the markets that precede the spot market, the six-month-ahead auction the ISO might do that's strictly voluntary by participants, a year ahead deal with a marketer, a five-year-ahead long-term contract, all of those arrive at the spot market and bid in their deal in a contract for difference, so it works the same.

And also I point out that in our approach we have talked about incorporating a forward market requirement and it's still under discussion. We do have concerns about that and we're still discussing it, but we do believe that a spot market component is very important. And I believe some of the other proposals do not have a spot market component.

Some of them have a reconfiguration auction just among suppliers that help suppliers who are broken make up for their loss, but they don't seem to really have a spot market and we believe one is needed.

MS. FERNANDEZ: Mr. Lukas?

MR. LUKAS: We support the auction approach, but I think our point is that just relying on the spot auction alone in the absence of dealing with the lumpiness issue, the problem is if you're building a significant amount of capacity in a region and you create that excess, that lumpiness, you know, that really affects the auction prices.

So we need--we see the auction more as a balancing market. Under the current circumstances, the only way we would go a new plant is to have a power purchase agreement, in order to be able to finance it and support it.

So that's why we think the demand curve type approach needs to really kind of be taken into account and the auction is more of a balancing market. If you just primarily rely on the auction on a short-term basis, it's just not going to work. You're going to have too much lumpiness in the market.

MS. FERNANDEZ: David?

MR. LaPLANTE: In terms of whether all the resources should bid into the auction or not, I believe the objective there is to assure that nobody withholds capacity from the market and you get a fair auction.

I think that could be accomplished by everyone bidding into the auction and making that a requirement. You could also just hold a residual auction and assure that all the other capacity is tied up.

So I think the objective there is the same and it's more of a mechanical discussion on how you get there.

In terms of a spot market, I think we need to evolve the proposal further to allow for LSEs to trade capacity rights closer to the time in. If there's an auction today for three years in the future, when we reach three years, there should be a way for the load to somebody who lost a contract wants to get rid of their capacity should be able to sell that capacity to the person that did it at some price. So I think that is an enhancement of the proposal that needs to be developed.

MS. FERNANDEZ: Mr. Reeder--oh, are you done?

MR. LaPLANTE: Yes, I'm done.

MS. FERNANDEZ: Let me ask another. I think I have gotten a sense of where the panelists are.

In the northeast, there has been -- and I mean it varies somewhat in the states but it's a region of the country where there has been a good deal of divestiture. There is the state programs or many of the states have retail access and have pursued that as a policy choice.

What do you think this type of centralized capacity market? Is this the type of system that is necessary for states, or a region that has a lot of retail access? Do you think it would work in areas of the country that have not had a lot of divestiture or the states have decided not to get into retail access?

MS. CARRADO: I think it could work anywhere. In states that don't have retail access, I think you could provide more flexibility depending on what kind of state programs there are.

One of the benefits to the centralized auction and having the capacity payment transfer with the load, it's an automatic process based on the auction price. It gives a forward clear visible price for capacity that everyone knows in advance what that capacity is going to cost them. And I think that is a huge benefit to the retail access program.

MS. O'NEILL: Yes, I also believe that it can work in areas of the country where they've not decided to go with deregulation as well as markets that are restructured.

It offers an efficient way of ensuring that you've got sufficient resources online out into the future and it inures to the public good.

MR. LaPLANTE: I think one of the driving factors behind the design from the market participants was to deal with retail access, and choice, and having a central buyer. An alternative name we haven't burdened you with is "the central buyer" where, because you don't know who is going to be serving the load three years into the future, you have an independent entity just making sure that the capacity is available, and in assigning the costs in the future.

I am not sure that it is necessary to do this.

It certainly could be done anywhere. I am not sure that it is necessary to do it in other areas of the country that don't have as much retail access.

I think in terms of--in getting to some of Kevin's earlier questions--I think the Commission might offer principles for each Region to meet, rather than trying to force a National Resource Adequacy Plan onto each Region.

I think resource adequacy is heavily woven into the whole institutional structure in each Region, and trying to force something that works for an area with divestiture on an area that doesn't have any divestiture may create a lot of confusion and not get us where we need to go.

MR. LUKAS: I agree with the other panelists on that. It works with or without retail access.

Then you have to look at the degree of retail access. Obviously it works best if there's a lot of competitive people, from a developer viewpoint, bidding for capacity. But you run into situations even in New York City where there's a certain degree of limited retail access. It's not highly diversified, the amount of load that's distributed among the ESCOs. You really have one person, one big utility bidding for it, anyhow, and it still works. It just needs the right long-term planning horizon.

MR. GRAMLICH: Could I just follow up on that? What happens in the states in the Northeast that don't have divestiture, don't have retail access, and are essentially bundled retail states?

Do they just essentially self-supply from the load-serving entity from its own generation such that the ICAP markets have not been something they have had to pay much attention to?

And if this type of arrangement, this new replacement arrangement, went into effect that those bundled states would just view it as a voluntary option that they wouldn't need to participate in?

MR. LaPLANTE: Actually, I think in New England all the utilities are members of NEPOOL and the ISO. So they all have the same obligations. So they would need to participate and meet those obligations.

A vertically integrated utility might have its own resources available to meet it, so it sort of nets itself out of the market. But they are subject to the requirement. I think that is important.

MR. GRAMLICH: So it is a regional requirement, but they can--

MR. LaPLANTE: Right.

MR. GRAMLICH: --just beat it based on the state-driven method.

MR. LaPLANTE: Exactly. Vermont I think is still regulated. If they have an IRP process in Vermont, the results of that procurement would let them meet it.

MR. KELLY: I was going to save this question for the end, but I think the timing is right for asking it now.

In response to Alice's question, many of you said that a centralized market for capacity can work in any region. But I would like to ask a slightly different question:

What should the final rule require?

Should we require a centralized market for capacity in every region?

Is that your recommendation?

Is that the only thing that would work?

Is your recommendation to allow the Northeast to have such a market? To require the Northeast to have such a market?

I won't recite all the list of options I gave you earlier, but--and anticipating David LaPlante's answer of just articulating principles, once we get the answer to the first question, could you think about what those principles might be?

I mean, is it a principle that there should be a centralized market for capacity? Or is that too detailed?

Maybe we could begin with Ms. Carrado. Especially your company serves a lot of the Midwest. You have Kentucky and Indiana that are not retail access, Ohio and Michigan that are, and what should we require in the Midwest?

MS. CARRADO: Just putting my--well, two things--putting my generator hat on, and also provider-of-last-resort obligations--I think the goal should be in each region that you have a tradable resource across the region. So you want seamless trading.

That being said, I think you can allow for the regional differences in the specific structure of how do you meet the requirement. But there needs to be some level of consistency so you get rid of those seams.

For example, how do you define source firmness?

How do you define recallability rights on the energy when a resource is being sold from one region to another?

The deliverability requirement I think is important.

The obligation period would give you consistency across the regions.

So I think there's a minimal set of principles that need to be consistent across the region. And given that, I would love to see FRPM everywhere, but the reality I think is that there could be regional differences in states without choice.

MR. KELLY: Would you require a centralized capacity market? If you were writing the FERC Final Rule, would you require that in every region?

MS. CARRADO: I would strongly recommend it.

MR. KELLY: Because you think it works well. But if you were writing a requirement, are you convinced that that is so good that it ought to be a requirement everywhere? Or is it something that you would allow regional discretion on so regions could choose it, but other methods could work in other regions that chose not to go that way?

MS. CARRADO: I think if it were a requirement, it would work, and it is good.

MR. KELLY: Yes, I understand that. But should it be a requirement?

MS. CARRADO: Yes.

MR. GRIFFITHS: Yes, for our region. We're very careful to say we don't want to try to tell other regions what to do. It has worked well for us. And we believe that some sort of required auction is what should go on for the foreseeable future. We simply don't see energy markets as a substitute for adequacy.

And I guess we really see reliability as a public good. I mean, there are some customers for whom that may not apply. But for almost everybody, it's a public good. And we really think that a centralized auction is the way to satisfy that. And our experience with other approaches has been not so good in terms of capacity. And I know that the PJM market monitor continues to express the strongest reservations about the competitiveness of the existing capacity markets in our region.

So I think that for our region and the expanded region, it's a good solution to have some sort of centralized system, but I don't want to say that the West Coast or the South ought to do that.

MR. KELLY: Mr. LaPlante?

MR. LaPLANTE: Perhaps. I think principles are good. Imposing a central purchase requirement or a central auction on the country I think first would require that ITPs are in place and operating to have an independent entity that did it.

If an ITP isn't up and running, I don't think that having an incumbent utility running a competitive auction would carry a lot of credibility. I think that would be difficult to pull off.

So I think if you're going to do it, you have to assume that you have an ITP to run the auction, an independent entity.

Secondly, I'm not sure it would work in a hydro-based system in terms of procuring resources. I haven't really thought through this issue, but I think it's a question. The requirement out in the West, reserve requirement, might be as low as your 12 percent, and that's because the hydro resources are variable in output. They're very reliable, but it's all energy-driven, so you don't really know how you would be procuring. You're guessing about the energy in the future.

The thermal resources in the Northeast you can run through the statistical calculations and come up with a requirement. So I think you need an institution in place, but I would support flexibility and each region coming up with a set of fairly strong principles. I think Regina's concept of defining a product, though, may be a good principle. She went through a tick list of seven or eight things as a product. That may be an alternative approach.

MR. KELLY: Thank you.

MR. LARCAMP: Could you tell me how much the centralized market feature is with -- what's the relationship there to the fact that these markets are organized markets with thousand dollar safety net bid caps? It seems to me that there is an acknowledgement that for certain types of units, that's just not going to be enough to get generation built.

I'm wondering because where we don't see organized markets, we do have a problem with volatility. And clearly the organized markets with the bid caps do some of that, take away the volatility. But I'm trying to see in those areas of the country where we yet don't have organized markets, is there a relationship here between the bid cap, if you will, you know, circuit breaker, and the need for these centralized markets?

MR. LUKAS: Can I jump into that question? Or were you asking David?

MR. LARCAMP: Because ultimately, whatever the Commission adopts, it wants to make sure that there is enough built or that there is enough demand response. Both accomplish the same objectives. And we haven't seen a lot of demand response yet. I mean it's getting better. But in the Northeastern markets, I think frankly that I'm trying to look at where we will create the demand curve, if you will, you know, in fairly large markets where we have a relatively insignificant portion of load that is demand responsive today.

MR. LaPLANTE: I think your question actually applies to both organized and unorganized markets. The choice was made that $1,000 price cap was necessary for essentially regulatory reasons, political reasons. I think that implies that you would need some form of supplement payment for capacity. And I think that holds true whether the market is organized or unorganized.

If you have a market without energy price caps, one could think of it as an experiment to see if in fact that does produce adequate resources. In terms of the Midwest price spikes in '97 or '98, apparently a large amount of peaking capacity was built in response to that. So it could be -- I'm not sure the problem is different for organized or unorganized markets.

MR. KELLY: I understand that in sort of the nonorganized markets the Commission may need to impose the must offer requirement too. But I don't see a must offer as necessarily meaning an organized central capacity auction spot market-type of arrangement.

MR. LUKAS: I think, Dan, you mixed up a lot of concepts there and I think actually it's good that you ask the question that way, because one of the points I want to make is, you could ask the question in terms of what if you don't have a capacity market? There is no capacity market. You have to think about what is the nature of the capacity market. It's to allow developers to recover their fixed costs.

Now if you don't have an organized, or some kind of structured capacity market that's long-term in nature, you have to by necessity if you're going to develop, recover your costs through the energy prices. So that's one of the benefits of having a capacity market, that you can have energy prices that reflect more variable costs than capacity markets that reflect more fixed costs. So you have to look at that hand-in-hand.

Now we had thought from a -- and if you look at the experience in New York City and New York State this year, we had record warm conditions. The ISO is indicating that there's a shortage of capacity. At the same time, because of what we believe was overmitigation in the energy market and a collapse of the capacity prices at the exact time, that we're saying we need new capacity built, it just doesn't work.

So they do go hand-in-hand, the capacity and the energy mitigation. That has to be looked at together.

Now getting back to the adjacent region question, I think it's just common sense that if you want to share resources between the regions and maximize the deliverability of the capacity, that you have some form of standard products that have like similar procurement periods. It's either winter/summer, three months, six months. So that's a good idea. And they should recognize local constraints.

But I do want to reemphasize, I think your question is good about development of distributive generation and the demand-side type solution. They all have to work together. But I think to the extent -- the other thing I wanted to point out was that there was a mistake made in our company to some extent in the perception that capacity prices aren't pipeline demand charges like it is in the gas business. It's not like you're guaranteed these recoveries year after year after year. You have to look at it as an auction-type process. But they're integrally related to the energy price mitigation issue.

MR. KELLY: Mr. Reeder?

MR. REEDER: I'd like to address a couple of subjects. In terms of the demand resources and their role in the $1,000 bid caps and the resource market, I guess I just want to point out that there is a chance, maybe a decent chance, that in the long run with enough demand-side response as really part of your capacity mix, if you will. So instead of meeting the top, you know, 25 percent of your load with lots of peakers and hardly ever demand response, maybe you meet it with lots of demand response and hardly any peakers, in that world which we might evolve to, peakers can bid in at $90 and get $150. Demand response sets the clearing price. They can bid in at $90, get $700 when demand response sets the market clearing price.

You can grow to a situation where the demand response are your new peakers, and the peakers are at a level right underneath that, and they would be receiving prices well above their bids for enough hours that you wouldn't need a capacity market.

Now also in that situation, you might not need the $1,000 bid caps because the demand response provides the price spike moderation and maybe the mitigation of market power.

But where we are right now, I think we are not at all ready to hand this job, which is a really tricky job of getting the right prices to get the right amount of entry, to hand it over to the two or three heatwaves each year. Because the energy market isn't working really well. It's not set up to work really well in those extreme hours because of the lack of demand response.

So I see the $1,000 bid caps and the resource adequacy revenue stream as needed perhaps on a temporary basis until the market matures where the demand response allows it to work like most markets and not have a separate capacity revenue stream.

MR. BANDERA: Mark, let me ask you a question regarding demand response and capacity markets.

Would you then, sort of to add to the ability of demand response to participate, would they be able to receive capacity payment for the amount that they can reduce or shed load in the market so they would also be able to participate and receive payments to maybe invest in demand response technologies based on these capacity markets?

MR. REEDER: Yes. And the New York ISO currently has I think over 500 megawatts of what's called special case resources which are demand response or sometimes they're generators behind the meter that are receiving the ICAP payments.

I wanted to now comment on the demand curve approach and just make sure it's clear that the demand curve approach that New York PSC staff has proposed in no way is tied to the need for load to respond by not demanding. The meters isn't the key.

The demand curve, you take a given peak load that the ITP has to deal with, it's the demand the ITP makes for resources. So if your demand on peak is 30,000, you may need 36,000 for your requirement, but you may demand 37,000 if that extra 1,000 price is right. And it's the willingness of the central procurement body to buy a little more or a little less. It's a different kind of demand.

I want to ask the question about centralized procurement. The demand curve approach requires centralized procurement because it requires the centralized body to buy, if you will, this public good, which is a little bit more capacity than the minimum requirement. And we haven't really thought up a way to disaggregate that and try to encourage all the LSEs individually if your requirement is 8 megawatts by 9, or if your requirement is 15 by 17, it seems to only be something that you can do if you have a centralized procurement. And it's only at the centralized procurement stage you find out how much is out there and at what price you can get it in aggregate.

So we would in terms of should it be required throughout the country, I don't think we know enough about New Mexico or places like that to really know. We're really focusing on our environment. Should it be required throughout the Northeast? Well, to the extent you think the demand curve approach produces some real benefits, it needs the centralized approach. And to the extent you want the say three Northeast regions to coordinate, and I think that's a good idea that they do, then it would be good for all three to use it.

And I think there are some other things you need to coordinate. I know the JK Group is doing a good job of trying to get as much coordinated as you can, and so one of those is the timing of the auctions.

I think some of you are familiar with medical school graduates go to residency programs, and they have this very elaborate program where they all put it in some big computer and rank their preferences, and it's a centralized decision. One person gets their first choice, one gets their second choice. And it's been pretty much proven that it's a superior approach than to just have everyone rant, you know, send their letters to their various residency programs. And I think that works the same way for the procurement of regional resource adequacy. If someone is thinking about exporting to New York from Pennsylvania or maybe selling in Pennsylvania, I think you can get a better result if they place their bid to wherever wants the most and let it be solved in one coordinated fashion.

MR. KELLY: Thank you. There are a number of cards up. I think the order was Mr. Lukas, Mr. Griffiths, and then Ms. O'Neill.

MR. LUKAS: Briefly, I'd just like to comment on the demand response resources. We're in support of developing them. We have a business unit that works on that.

But I would want to point out they shouldn't count equally towards the adequacy requirement, because frankly, they just don't produce energy 24/7 like a combined cycle unit would, and you really have to kind of determine if they're coincident with the peak to see if they reduce the peak one on one.

So it should be more of a load modifier I guess is our point, rather than counted as capacity.

MR. KELLY: Could I follow up on that? Suppose -- some of the proposals were stated that all LSEs or all customers would have to pay their fair share. But in a retail access state, if you have let's say an industrial customer who says, rather than pay an extra whatever it is, 18 percent for power to pay for a resource adequacy requirement, I will opt to shut down when we get near the peak. It's a business decision. I want the freedom to make it. I won't contribute to your peak. I won't contribute to your requirement. Don't ask me to pay for it. What's wrong with that?

MR. LUKAS: Essentially nothing. You need the assurance that they'd be coincident with the peak, that they're definitely going to be offered any peak to assure the payment. But I think there could be some kind of load modifier factor applied, because if you had all demand response and no generation, you wouldn't be going anywhere. So you kind of have to equivocate the two a little bit.

They're not as efficient. They're not producing energy, just reducing energy. They're not putting out lower cost energy 24/7. So that's why we think some kind of load modifier factor probably should be applied, discounted a little bit. But I'm not looking to penalize it.

MR. KELLY: Okay. We'll go to Mr. Griffiths, Ms. O'Neill and then to Ms. Carrado.

MR. GRIFFITHS: I just want to link a couple of things I think that the expectation that demand will serve to satisfy adequacy requirements has to be considered in light of how forward you are going in terms of auctioning.

Demand does not function the same as generation, and there are cross-cutting incentives there. So if you're looking three years in the future, many of the existing demand responders may not be able to make that kind of commitment. You may get different kinds of demand response, but I think for a lot of large industrials that now are participating, it may be difficult for them to make a three-year commitment forward to respond in a particular way.

MR. MEAD: Could I just follow up on that? Are you suggesting then that if there is a requirement for a centralized auction fairly far in advance like three years, that that requirement would tend to crowd out demand response programs that might be able to supply adequacy on a shorter timeframe?

MR. GRIFFITHS: Yes.

MR. MEAD: Do others agree with that?

MR. LaPLANTE: I think it poses problems, but I don't think the problems are insurmountable. I think if resources are allowed to bid in and there is a delivery structure and a penalty structure for not delivering, and I think demand resources would be able to make business decisions and do similar things as supply resources.

But there are problems of measurement. If I'm a factory three years into the future, my measurement may have to be based on my load three years from now, not my load today. So I think there are some issues there that have not yet been explored but I think can be resolved.

MR. MEAD: The way I understood Mr. Griffiths' point, and perhaps correct me if I'm wrong, but it is if we're deciding three years in advance what mix of resources we're going to use to meet the adequacy requirement, well then three years in advance there's more supply-side resources, you know, in the auction and fewer demand-side resources, because demand doesn't know whether it's going to be available, whereas if you held the auction a year and a half or a year in advance, you might have more demand response resources available. Is that the basic gist of the point?

MR. GRIFFITHS: That's fair.

MR. LaPLANTE: That's probably true. But I think there are ways to integrate demand response into a forward auction.

There's also in the JK Group discussions of not procuring all of the requirement now for three years from now, maybe procuring 85 percent of it or something. That might be another way where closer on you're procuring just a little bit more. This is something that might help the market monitors get more comfortable with the approach.

MR. KELLY: Okay. I want to go to Ms. O'Neill and then Ms. Carrado, and then Mr. LaPlante, you had your card up maybe for perhaps another, and then we have some other questions we want to get to. Ms. O'Neill?

MS. O'NEILL: I'd like to take us back for a minute on a higher level to what we're trying to accomplish and what we're really trying to accomplish is adequate resources at the lowest possible cost.

That involves really bringing new generation on line. And I think when we're talking about most of these proposals, you know, do you want to bring new generation on line or do you want to get more money to existing generators? If you want to bring new resources on line, I think the way to do it is in the kind of direct incentive for new generation that we're talking about.

It's highly speculative to assume that you're going to get new generation on line by giving money to existing generators in the hope that they're going to bring in new resources that will compete with their existing resources and bring down the overall costs and rewards of that.

I thought Commissioner Welch's comments filed in this docket were useful in that regard.

If you're looking to--I think then if you think there's a need to get additional money to generators, you really need to look at a couple of things on that:

One, most existing generation is being recovered either through rate base or through stranded costs or some combination thereof.

To the extent that there are merchant plants that have come online, most of them could not really have done so in a reasonable -- most markets don't have capacity payments now. In the Northeast where they do have them, they couldn't have come online in a reasonable expectation of consistently getting money through those capacity markets, because in times of excess, the value of that is zero.

The fact that some generators may have paid too much for plants, may be a problem right now, but I think we have to avoid designing a solution that simply deals with the short-term problems of those generators, as opposed to what's long-term policy.

In general, plants that cannot recover their peaking, or other plants that can't recover their costs through well-functioning markets, are inefficient and should go off line and make room for newer and more efficient resources.

Now, of course, to the extent market mitigation is holding down the prices, we need to deal with that. I'd say that the way to deal with that is to loosen up on price mitigation. The additional point on that is, in some markets, perhaps where there has been capacity payments, there may need to be some kind of phaseout to deal with that at the same time that you are lightening up on mitigation.

But I think that's an accommodation, as opposed to a necessary mechanism for assuring resource adequacy.

MR. KELLY: I want to go to Ms. Carrado, and then rather than take repeat cards on this generally, there is another area we would like to explore after you make your comment.

MS. CARRADO: I wanted to finish up on the demand side resources getting capacity credit. There are models out there where you can model the various programs, the reliability of the system, with and without the programs, and you need to look at certain things like how many times a year is the program load going to be interrupted? Is it going to be during the summer? What's the notice requirement. And through that, you can set criteria in order for the demand-side programs to get the capacity credit.

And also you need compliance criteria, such that did they interrupt when they were called to interrupt, and if they didn't there could be penalties involved with that, so there are ways and it is working.

MR. KELLY: Thank you. Mr. Lukas, I'm going to skip you, with your permission.

MR. LUKAS: I would like to rebut Karen, though, on one important issue. I just think it's a very bad idea to have a bifurcated market.

MR. KELLY: Thirty seconds?

MR. LUKAS: Thirty seconds. I will just say that I think it's a very bad idea to have a bifurcated capacity market, and inefficient units will bid too high with the energy, and it will eventually shut down. And you just have to look at the NGPA when you had Section 102 and 107 gas, and it would be a nightmare.

MR. KELLY: Alice?

MS. FERNANDEZ: Actually, I had a couple of ones where I'd just do some clarification. As with Ms. Carrado's and the JCAG, is the main difference between your approach and the JCAG that everyone would have to bid in?

MS. CARRADO: No, our approach is essentially the JCAG approach, and in both, all resources would bid in.

MS. FERNANDEZ: Okay. Actually, if I could ask Mr. Reeder another question for sort of clarification, in the demand curve approach, if there's additional resources that are required, does everyone pay for that?

MR. REEDER: Yes, and another way of saying it is that the LSE requirement, the current requirement in New York is 118 percent peak load. If there's a large number of low offers out there for capacity in the central procurement process purchase 121 percent on an aggregate basis, then all the LSE's requirement is 121 percent.

You can think of it -- and they can pre-buy, you know, say, however much they want, through bilaterals and things like that.

But you can think of it kind of like ancillary services and the way they are procured. The ISOs procure ancillary services on a daily basis, and then they charge LSEs an uplift per whatever, per megawatt hour, I believe.

To the extent the ISO's centralized procurement process goes for 121 percent instead of 118, it would send a bill, if you will, to each LSE for the full 121 percent, less whatever they had already procured.

MS. FERNANDEZ: Okay.

MR. KELLY: Derrick, a question?

MR. BANDERA: I have a question regarding the different payment of the new and old generators. It seems that when you're proposing that there be a difference in payment structure between those two entities, and one question, for instance, I'd like to ask is, what if a generator in a neighboring region wanted to supply capacity to another -- to a neighboring region? Would that generator be qualified as a new resource, if it hadn't previously been participating in the market?

And, if so, it sounds like everyone would want to just switch out into neighboring resources to be -- to get this new resource payment.

MS. O'NEILL: Let me clarify, first of all, what the -- that it's not -- it's not so much a differential in how they are paid; it's just that all that you're auctioning is an incentive, and you're basically saying we want to know how much it will cost in the way of an incentive payment for a new resource to come online, and that would be over a five-year period, and then it goes away, so there's no standing obligation or differential in that respect.

Secondly, I think that what you would be doing is really a planning within a region, and you would be -- the ITP would be counting the resources in its region. You'd be looking at new resources going out for auction, essentially for resources within that region.

Now, I do think it's an interesting question, because it's something I don't think resources that are currently existing in other jurisdictions ought to be able to bid in. Essentially you count the resources in your -- in your area, and that's the way the planning is done.

There is an issue, I think, if there is a -- if the most appropriate -- in general, you're counting and you're trying to develop resources in that area. There are circumstances, certainly, when it may be more efficient to locate a plant in the system over, and it may be that -- and I don't know exactly what the mechanism would be.

I would think that some coordination between those two control areas might allow somebody to locate a plant there that would be counted next door, at least for some period of time, but I haven't quite thought that through.

In general, I think it's the default position, as you count what's in your area.

MR. BANDERA: So the default position is that each region is --

MS. O'NEILL: Resource adequate.

MR. BANDERA: On its own?

MS. O'NEILL: Except that -- and let me make an important caveat to that. I think that the -- when the ITP is doing its planning, while it may not count resources -- you wouldn't be counting contracts that are in another -- for plants in another area.

You would know essentially what your import capability is, and what the history of imports is. Then the highly probable likelihood of being able to highly-probable import capability could be counted in doing your overall planning and assessing how much of a reserve you needed.

MR. BANDERA: Would those resources that you are counting on as imports, be allowed to be capacity resources in both areas, then?

Or would they --

MS. O'NEILL: Would they be getting incentive payments?

MR. BANDERA: If you're relying on the import capability for resources to come in, and you're just relying on just the import capability, would those generators on the other side of the import capability receive a capacity payment?

MS. O'NEILL: No.

MR. BANDERA: Okay.

MS. O'NEILL: No. Essentially what we're trying to do is make sure resources come online, and beyond that, you're letting markets work and power flow wherever it makes economic sense.

And basically, you shouldn't have to worry too much about that. If everybody resource-adequate, then you don't have -- then I think you do not have to get into all of the careful counting of resources there.

MR. BANDERA: Well, if everyone was resource-adequate, you wouldn't have a problem in the first place.

MR. KELLY: Ms. O'Neill, I don't know how familiar you are with FERC's gas regulation history, but we had something called vintage pricing at one time, where gas molecules from new holes in the ground were worth more than gas molecules from old holes in the ground, and the law of unintended consequences ran wild.

Why wouldn't that happen with old and new electrons or electrons from old and new plants?

MS. O'NEILL: For one, because I think you're doing an incentive for new generation that goes away, so that they -- this isn't something that perpetuated for any period of time. It simply is an incentive as a startup.

MR. KELLY: Mr. LaPlante?

PARTICIPANT: I think New England is in a capacity surplus situation at this point, but our experience is showing that new capacity -- this is fairly efficient capacity. If you look at their revenues, including their ICAP energy ancillary service revenues over the course of a year, they're not recovering their costs, the costs of putting the thing in the ground.

So, it seems that some form of capacity market is needed or an uncapped energy market. But I think there is a theoretical question with very severe practical implications that's worth exploring, which is that if you've got new combined cycles, which we have a lot of in New England, they're setting the price, many, many hours in New England, so the new combined cycles, as a class, are not receiving very much contribution to their capital recovery.

And then you have resources that are even more expensive to run, a peaking a unit above the new combined cycle. They're receiving very little capital recovery in the energy market, so that seems to argue that some form of additional recovery is needed for those units, even to make their costs.

MR. KELLY: I'd like to return to the topic of what the final rule should say. Mr. LaPlante, you suggested at one point that perhaps FERC should articulate some principles, and it seems to me that, you know, unless we simply step away from the resource adequacy issue, we have to actually require something or there is no requirement.

And that, indeed, any multistate area would probably need an agency like FERC that deals with interstate commerce, to have a requirement that goes across entities in several states, and a requirement says you have to do something.

Now, a few weeks ago I was asked about principles, and I articulated three: It should be forward-looking, treat supply and demand equally, and fit with the state laws in retail access and non-retail access states, and give states appropriate roles in choosing the level.

When I heard Ms. Carrado earlier articulate some pretty good principles off the cuff, they were at a much greater level of detail. So I guess the question I have is, at what -- if we were to articulate principles, how much detail should be in them, and if you get too great a level of detail, isn't that tantamount to doing what Mr. Reeder suggested, at least for the Northeast, and saying, well, if you're going to do something very specific, you have to really mandate it for everybody, at least in the Northeast, so that everybody is following the same system?

How do we balance those two tensions? That's for anybody who would like to address that.

PARTICIPANT: Well, I think the -- I think the three -- requiring a multistate entity to file a plan that is consistent with the principles, I believe would be the best approach.

I think the fourth principle that Regina mentioned of creating a product, would be an additional principle, if you will, that part of the plan would be the creation of this product and how you -- this is what the plan has to produce. It's got to produce this capacity product with these various attributes that people can trade within the region.

MR. LUKAS: Specifically, I would have to think, but I would say that generally, directionally, I would err on the side of a centralized market and having a little bit more detail than a little bit less detail.

And I think specifically we have to kind of deal with this long-term demand situation where generation gets built, and the price signal is there to support the financing of the plants. I think, as Mr. Reeder does, this demand curve type proposal would have more of those elements in the plan than less of them.

And I would have some consistency between the congestion control areas, as long as you recognize and give some flexibility for local constraints. But I would say to err on the side of a little bit more centralization than the design.

MR. KELLY: Just to clarify, that would be a for a national rule.

MR. LUKAS: Yes, it's hard for me to speak about New Mexico, but certainly in the Northeast.

MR. KELLY: Ms. O'Neill.

MS. O'NEILL: I would agree that if we're going to specify a resource, that if you're going to address a resource adequacy mechanism, that it is better to be more specific than less, particularly to deal with the seams issues between areas. That would seem to be necessary for the kind of new resource assurance program that we recommend, I think, some common understanding of how one counts and conducts auctions and payment protocols would be needed.

I'd like to reserve some -- you know -- I want to think about that some more, because there may be some areas of the country where you have seams issue, and it seems to me there are some real issues there.

MR. KELLY: Just a clarification. When you say be more specific on auction protocols or auction details and payment protocols, is that -- would you say that if you have an auction, it has to be specific, or would you say every region has to have an auction with these payment protocols?

MS. O'NEILL: I guess what I would say is that you should have an auction mechanism with -- and I'm not talking about a high level -- you know, a tremendous level of detail, but that there be some level of commonness in the protocols, yes.

MR. KELLY: Thank you. Mr. Griffiths?

MR. GRIFFITHS: Just one point on the auction issue: I think we do need to remember that you have to look past that and recognize the fact that there can be a failure of markets to supply what's needed, and that's why our proposal includes a backstop mechanism, so that ultimately if everything goes wrong, the ITP will be responsible for going out and in one way or another, securing the needed resources.

MR. KELLY: Ms. Carrado?

MS. CARRADO: I was going to say that on your three principles and what Dave LaPlante added as far as the tradeable capacity product, I think that's good way to go.

4

The things that could be flexible are the details of how -- the study, how the reserve requirement is done in methodology, and then the number itself could be set by the state and the ITP together. And then to look at the region, whether they have retail access or not, I think would determine is the burden to supply the resources ahead of the operating year and is that a regional requirement or is that load-serving entity-by-load-serving entity.

And I think that whether there is retail access or not would differentiate that requirement in those regions.

MR. KELLY: Just to follow up on one of the things you said, Mr. Griffiths earlier was worried that we didn't want 100 percent reliability; it's too costly. And you indicated that maybe the state and the ITP together should set the level of reliability.

The FERC NOPR proposal is for the states in the region to do it with no role from the ITP. Would you change that? And I guess I'd ask Mr. Griffiths who he thinks should set the level of reliability and hence cost?

MS. CARRADO: I think the ITP needs to have a very defined role there, and that they need to do the load forecasting. They have experience with reliability methodologies and how to set reserve requirements.

The states also do, to some degree, but I would see them working more jointly together in doing that. The state may have a higher role in how the study is done with the criteria. Is it one day in ten years you have to meet NERC criteria, and all that kind of stuff? But I think the ITP needs to be right there with the states in doing that.

MR. GRIFFITHS: I take my past experience as a staffer at the Pennsylvania PUC. When we did the rate cases many years ago, the fact that PJM had established a target for reliability in terms of reserves was something that was extremely useful for the state.

I think that most states would take that kind of guidance. The question about what you pay for that is something that in that regime was decided at the state level, and now may be decided more in the markets.

In PJM, we don't have the issue of states that don't have retail access, and so it's not such a problem.

MS. FERNANDEZ: I was thinking almost as a sort of a followup to that. If you have the demand curve reserves, I mean, it seems like you end up coming up with a much more complicated process, and sort of different judgments as to how much extra you'd like to have.

And in that case, where it seems like you're going beyond sort of the typical reliability requirements of one day in ten years; you're going into, well, normally, that would be 18 percent, but if the price is right, it ought to be 21 percent.

In that type of a situation, what would be the roles of the states in sort of determining how much additional reliability would be good for the region?

MR. REEDER: I think I can address that because I think you could have a demand curve approach for three adjacent ISOs, but not use the same demand curve. One area may want more reliability than the other may say, if we can get capacity for $20 a kilowatt year, we'll go for ten percent extra.

The other area can say at $20 a kilowatt year, we only want two percent extra, and so the market would clear at -- it would clear at the same price in all places, but the reliability outcome would be different in the three places.

So you wouldn't need to mandate that they use the same demand curves. And I guess I want to clear up a misimpression. I think having three adjacent areas all use a demand curve approach is better than one using it and the other two not, but it's not required.

You could have one area buy extra reserves. For example, New York could buy instead of 18 percent, it could buy 28 percent, but PJM and New England could just stick to the 18 percent that they have got.

MS. FERNANDEZ: Okay, I guess I was sort of getting at almost the question of who decides that it would be good for the public within the region to buy the additional amounts? I mean, it's something where -- I mean, is that the ITP? Is that the states deciding that a higher level would be desirable and that everyone in the region should pay for that?

MR. REEDER: I'm not sure. I mean, the way it's operationalized right now is that the New York ISO's committees have all the market participants involved in that decision, and they're going to have a product that probably won't have full agreement on, and I assume it comes to the FERC for resolution.

A new way of doing it in the future, I don't have any expertise to add there.

MR. LUKAS: If there is a regional state advisory council, the shape of the demand curve could certainly be something that they would be involved with and involved in a submittal to the Commission.

MR. KELLY: David Meade has a question.

MR. MEAD: I'd like to talk about the issue of deliverability of the resources within the context of the central auction. It's, of course, more expensive to deliver energy to a load pocket like New York City or Boston or San Francisco than it is in a generation pocket.

So actually I have two related questions: One is, how would the -- in deciding what resources qualify to supply in the central auction, how is deliverability taken into consideration? Does each resource need to deliver into the load pocket, or not?

And a second, related question is, if it's more expensive to deliver energy to a load pocket than someplace else, what I heard in terms of the proposals was a single market clearing price for all resources throughout the region, and I presume that also meant that the loads were paying the same amount.

Is that consistent with the sort of differential cost of delivering into different parts of the region?

MR. LUKAS: Okay, I think there may some misconception about the JCAG proposal in its current form, based on what you just said.

Currently, the thinking is that each individual ISO would run an auction. The auctions might be run at the same time to make it easier for people and to clear things, and people know where they stand.

But it would be three separate auctions -- New York, New England, and PJM -- with three separate clearing prices, so if New England is short, we might pay more; if PJM was long, they would pay less.

MR. MEAD: That's fine, but even, say, within New England, it costs more to deliver into --

MR. LUKAS: That's what I was going to answer, the second question, which is the deliverability question. And we've taken a cue from the Commission made our regional solutions to deliverability.

In other words, PJM at this point has an interconnection standard that requires generators to build sufficient transmission to be interconnected to receive capacity credit.

New York has a zonal approach where a load within a zone must purchase a certain amount from within that zone. New England is still developing a deliverability requirement. So each region would treat deliverability independently in the auction.

MR. MEAD: Mr. Lukas?

MR. LUKAS: I think, just briefly, I think distant generation should pay for the cost of transmission to bring it into a load pocket, and generation must be dedicated to prevent double counting. You really don't want virtual generation. You really want the real generation there for reliability purposes.

And that's why some of the questions about liquidated damages also reminds me in the gas days, we used to have big penalties for gas, $20 for gas if it's not delivered. The point is not to get the $20. The point is to get the capacity.

MR. MEAD: Just as a follow-up actually with both of your answers, let's say in New York, should customers in LSEs on Long Island or New York City pay more for resource adequacy than somebody in the Western part of the state? Or in PJM, should people in Western PJM pay more for resource adequacy that people in the East?

MR. LUKAS: I think the way the zones are set up and the way the costs are allocated, that can be taken into account. I think in Mark Reeder's demand curve proposal, he made the point that you could have different curves for different parts of the state. So I think you can accommodate the cost allocation issue. The question is, if somebody builds a plant in New Jersey and it's going to be counted to its New York load inside the load pocket, it should have a way of delivering there on a firm basis.

MR. MEAD: Mr. Reeder?

MR. REEDER: In New York, as was mentioned, we don't really have transmission deliverability be something the provider, the generation owner or the LSE has to deal with. We have locality requirement. So, for example, in New York City to sell ICAP to New York City, you have to be in New York City. You can't be in Buffalo and say I'm selling New York City ICAP and here's my transmission contract.

The ISO does studies of how much of New York City's reliability needs can be brought into the city from outside it, and it doesn't let any more than that amount -- and that requires that all the rest come from within the city. And certainly in response to your question of the different prices and different places, to the extent it's more expensive to build a generator in New York City, the market clearing price for the resource requirement is higher than New York City.

Just because it costs more to do business there. And if you didn't set it up that way, then no one would build in New York City because they wouldn't get a differential out of the ICPA market.

And so you really don't have an issue. I don't know if this was a clever way to dodge it or not. I wasn't involved in setting up these rules, but we just don't deal with these issues of buying transmission and moving it. Similarly, for the state as a whole, a certain amount of its resource capacity needs has to be from within the state, and that's a big pocket called the state.

If you want to bring it from Canada or you want to bring it from New England, you want to bring it from PJM, there's only a certain percentage of overall New York's needs that can be obtained from out there. And so you could have the maximum amount allowed from outside of New York being provided and create a constraint if you will in the auction so that the prices in PJM of people who sell ICAP to New York clears at as lower price than those who are within New York.

MR. MEAD: Ms. O'Neill I think was next.

MS. O'NEILL: Yes. And under the new resource assurance program, the ITP, who was looking at resources across the state, I think would be in a good position to specify if necessary and perhaps run a separate auction for a load area if it's necessary to make sure that resources are located in that area as opposed to other places.

In terms of exactly how to deal with that cost, I've mentioned before that under our program, we would want the cost of assuring reliability overall to be socialized as a public good across the region, although it may be appropriate. And frankly, we haven't gotten quite to that level of detail whether that because of the needs of particular areas or constraints in that area, whether it's appropriate to different that transmission base charge.

MR. MEAD: So in your view, people throughout the region should pay the same price for resource adequacy?

MS. O'NEILL: In general. As I said, we haven't quite to the level of detail because of those kinds of transmission constraints, I haven't quite figured out whether it would be a good idea to do a rate design that assigns more costs to some areas than others.

But in general, it gets passed through as a transmission-related cost as opposed to going through the LSEs.

MR. MEAD: Ms. Carrado is it?

MS. CARRADO: I wanted to say that if you don't have the requirement that within a region all the resources are deliverables or the load zones up front then if you have locational auctions or whatever you want to call them, and you don't get the price right such that the price is higher in a constrained area -- and this is all subject to market power considerations of course-- you're never going to get the right price signal that you need to build transmission to alleviate the bottlenecks.

So inherently, there needs to be some price differences when there's shortages even due to bottlenecks.

MR. KELLY: I'd like to close on the issue of how you enforce a resource adequacy requirement. The FERC proposal tries to get an enforcement mechanism that relies on something that's clearly FERC jurisdictional which says you pay a high rate for sale for resale power, which is FERC jurisdictional, if you're deficient under certain conditions.

To paraphrase a conversation I had with someone from the Northeast, they said, well, that won't work. The penalty is too low. And I said, well, there's no penalty in the proposal. We set it at the level needed to make it work. And they said, well, that level would be really high, so that's not feasible. And I said, well, how do you enforce it in the Northeast? And they say, well, it's simply a requirement. A load-serving entity has to purchase its share. And I said what if they don't? What if they don't write the check? They said, well, then there will be a really high penalty.

(Laughter.)

MR. KELLY: Doesn't it always come down to a really high penalty? Or does it ever come down to a curtailment? Or is there some third means of enforcing a resource adequacy requirement?

Ms. Carrado?

MS. CARRADO: I think the goal of the program should be that the penalties are never invoked, and that the regional needs need to be met.

So the penalty needs to be high enough to incent a resource owner or an LSE to go out and procure the capacity in advance. But if it's too high and it's a real-time penalty, then there are ways that they could avoid that penalty. So I think you need to look at both sides.

In the centralized auction, the penalty is never on the load-serving entity. It's on the resource owner. Because the load-serving entity's needs are always met because the total regional requirements are there.

MR. KELLY: But if a load-serving entity -- what if it says, well, I'm opting out of paying my share?

MS. CARRADO: If the opting out means it's opting out of the auction, so it's not procuring its resources from the auction, but there's still a requirement that it's self-supplying or has contracted for those resources bilaterally.

And there's also a requirement that those resources are committed to the region for the entire period.

MR. KELLY: And what if doesn't meet that requirement?

MS. CARRADO: Because the auction is held for the total load, the requirement is always met.

MR. LaPLANTE: The bill will be sent to the LSE based on the FERC-filed tariff as part of the operation of the pool. And presumably, the financial security arrangements would be such that the load-serving entity would be forced to pay what that bill was.

MR. KELLY: It's really quite different in the Northeast because of so many decades tradition of having reserve sharing, and a reserve-sharing contract is legally a sales for resale contract and has always been FERC jurisdictional. And there's sort of an implicit understanding that you have to live up to your contract.

But outside the Northeast -- this may be an unfair question for this panel -- where there aren't such contracts in place, the enforcement mechanism is a tough one I think, unless it's a penalty of the sort I've described. But I gather that in the Northeast it's just unthinkable that people wouldn't meet their share. They just have to, and you don't worry much about enforcement. Is that right, Mr. Lukas?

MR. LUKAS: Yes. And I just wanted to add, obviously, ultimately if somebody fails, you need the penalty. But you don't want to structure it that the people can kind of like wait till the last second and see if they can dodge the bullet on getting the capacity and say I'll take my changes and I'll get the penalty. You know what? I'll go bankrupt and I won't pay you. Because credit is going to be a big issue in collecting the penalty.

So whatever market design that you put in, you want to make it up front that they have to commit to the capacity so the capacity gets built.

Ultimately, if people don't live up to their commitments, then you need to have penalties and credit checks and all that. But if you just make it a way to dodge the bullet and they just hope that they don't have to incur it, that's not going to work.

MR. KELLY: Thank you.

Mr. Reeder?

MR. REEDER: I just want to I guess repeat because I'm not sure it was fully understood that when you have a centralized procurement process, the LSE itself is not required to do anything.

I'll give the example in a second. But they can avoid having to pay the bill that's sent to them if they self-supply, either by owning generation or arranging for their own contracts. But if they don't, the centralized procurement process buys it and then sends them the bill. And it's just a question of the creditworthiness.

MR. KELLY: Can they self-supply by saying -- by reducing their demand? Counting a demand-side resource as part of their supply?

MR. REEDER: Certainly. But I'll just give you an example. Right now what is the penalty for LSEs not doing their fair share of procuring ten-minute spinning reserves? There is none, because they're not required to procure ten-minute spinning reserves. The ISO does it centrally. How does the ISO pay for it? It sends them a bill. What do you do if they sort of say I'm not playing this game? Well, that amounts to them saying I'm not paying my bill.

I think under a centralized procurement process for capacity, it works the same way.

MR. KELLY: Well, not quite, at least as I see it. If the bill for the ancillary service is ancillary to transmission and in effect they're not paying their transmission bill. But would you say that the bill for capacity is part of the transmission bill? I think it's more part of the Northeast tradition of paying for reserves jointly, isn't it?

MR. LUKAS: I've been on both sides of the market so I can answer from the retail perspective. Basically you have to post credit with the ISO to bid into the capacity market. And if you don't have enough credit and prices go up, you're limited to what you can bid. So you have to have the credit up front for the capacity.

So it is credit-backed. The problem with the penalties is, as I said, is if you just make it so people can escape or try to take a chance to escape. I was thinking in terms of if you're going long-term, one of the things just to change a little bit, you should have some milestones if people have them contract long-term, kind of like gas precedent agreements. Because you're going to be contracting three years out.

MR. KELLY: Okay. Let me just note that we have five minutes left, and now for the first time, all six cards went up.

(Laughter.)

MR. KELLY: Before we get to that, do any of the other FERC Staff or Commissioners have a burning question that we definitely want to get in before we hear the comments on the last question?

(No response.)

MR. KELLY: Okay. Let's in one minute each, we'll go from my right to left, Ms. O'Neill.

MS. O'NEILL: I wanted to point out in response to -- well, first of all, the beauty of the new resource assurance program is that there is not an obligation on people and you're not ending up policing participants in the market.

Resource adequacy is recognized as a social good and it's passed through as a transmission-related charge. So I think you avoid a lot of those kinds of problems.

One thing I want to point out about some of the other proposals on the table is that they really seriously disadvantage competitive participants in the market who may not be in a position two years out to bid into various markets and therefore hedge their risks of -- you know, they end up taking the price that comes out of the auction as opposed to being able to utilize their own resources or bilaterals, that sort of thing, because they are not able to project loads, may not have the similar credit and those kinds of issues.

So there are serious competitive issues involved in most of the capacity proposals that are on the table.

MR. KELLY: Thank you. Mr. LaPlante?

MR. LaPLANTE: In terms of assigning the cost to the transmission owners, that's not something that's been discussed at the JCAG, but it may be an interesting way to finesse the load-serving entity issue where you assign the cost directly to the transmission owner. Okay. Thanks.

MR. KELLY: Thank you. Mr. Griffiths?

MR. GRIFFITHS: I guess your questions gets to the I'm not going to pay my bill issue. And in PJM, if you're a load-serving entity that's not a provider of last resort, if you don't pay your bill, you're not going to schedule and you're out of the market, and your customers fall back on the provider of last resort, which will take up the responsibility for providing capacity or whatever we're going to call it.

And so the real question ultimately is what happens to those last resort providers in our system. And I think that's really where you're going to have to depend on the states to some extent.

MR. KELLY: Ms. Carrado, last word.

MS. CARRADO: I was going to say that the penalties and the payments are really an equity issue. We didn't talk about load loss sharing within a region. I mean, the whole concept is that if one LSE is 10 megawatts short and the other is 20 long, well, the one that's 20 long is carrying the short one, because load will not have to be interrupted. So I think that's where you need to enforce some kind of payment and penalty mechanism so that there's not that leaning.

MR. KELLY: I want to thank this panel for a very interesting discussion. It's been very informative. And we will take a 15-minute break and resume on the half hour. Thank you.

(Recess.)

MR. KELLY: Welcome back. If the panelists will take their seats, we'll get started. Please have a seat.

We have for the second panel Michael Alcantar, an attorney that's speaking on behalf of the Cogeneration Associates of California and the Energy Producers and Users Coalition.

Kieran Connolly, Public Utilities Specialist with the Bonneville Power Administration.

Peter Evans, President, New Power Technology, speaking on behalf of the Silicon Valley Manufacturers Group. He's participating by telephone. Mr. Evans, are you in on the line?

MR. EVANS: (By phone.) Yes, we're here.

MR. KELLY: Great. I think we need to move one of the mikes closer to the speaker phone to hear him well. Mr. Evans, speak again. Let's see if we can pick you up.

MR. EVANS: Okay. Can you hear me now?

MR. KELLY: Just barely. I think we need to -- keep talking if you would. Just recite the ABCs. We have an AV technician working, and I think if you keep talking while he's working, it'll help us to work out the right volume level for you.

MR. EVANS: All right. How's this? Does this still come through pretty well?

MR. BRADLEY: (By phone.) This is Justin Bradley. I'm with Peter Evans. I'm the Director of Energy Programs for the Manufacturing Group.

MR. KELLY: Mr. Evans, are you on a speaker phone?

MR. EVANS: Yes we are.

MR. KELLY: Can you get on a regular phone, please? I think if you want people to hear what you're going to say, you'll need to be on a regular phone. The speaker phone is not going to work.

While you're making that change -- could you speak again and see if that works?

MR. EVANS: Can you hear me now? We'll call in from a regular phone.

MR. KELLY: Please do.

Mr. EVANS: We'll sign off.

MR. KELLY: Okay. Just to name the remaining panelists, we have Kellan L. Fluckinger, Senior Advisor to the Chair and CEO of the California Consumer Power and Conservation Financing Authority.

John Meyer, Vice President of Asset Commercialization, Reliant Resources.

Charles Reinhold, WestConnect RTO Project Manger, Electric Resource Strategies.

We are getting feedback. I'm going to ask the A/V person to try to take care of it, but we're going to continue while he's working on that.

We have Charles Reinhold, WestConnect RTO Project Manager I mentioned, and we also have Gary Stern, Director of Market Monitoring and Analysis from Southern California Edison Company.

Now has Mr. Evans dialed in on a regular phone yet?

(No response.)

MR. KELLY: Okay. We will do a check on whether he's dialed in after we hear from our first speaker, who is Michael Alcantar, an attorney, on behalf of Cogeneration Association of California.

Just before he begins. I'm sorry. I don't know the A/V person's name. Kent. We seem to have a big echo from the current system. Is there a way to eliminate that? You're not nodding yes or no?

MR. KELLY: All right. Apologies to the folks. We have some other speaker being piped into this room which is being picked up by the mikes and is creating some confusion.

At least for me, it is not so bad that we can't continue. So while people -- our Court Reporter is panicking.

(The feedback stops.)

MR. KELLY: Okay. Good. Thanks to everybody. Thanks for your patience.

One last check. Peter Evans, have you dialed in?

MR. EVANS: Yes, I'm back.

MR. KELLY: Great. We hear you loud and clear. Thank you.

MR. EVANS: Justin is going to call in as well.

MR. KELLY: That's fine. But it's only one speaker, you understand?

MR. EVANS: Right.

MR. KELLY: Okay. Michael Alcantar, you've been introduced already. Please begin.

MR. BRADLEY: Hello. Justin Bradley with the Silicon Valley Manufacturing Group.

MR. KELLY: There's supposed to be one speaker speaking on the speaker phone. Anybody who speaks is broadcast throughout the building. Peter Evans, speak when you're called on. We'll get to you shortly. Everybody else, please don't speak.

Michael Alcantar, please begin.

MR. ALCANTAR: Thank you for the third introduction. As we transition from the Northeast to the West, and I get to lead off, I'll borrow a Monty Python line that: Now, for something completely different. And not only by region, but by the particular comments that I'm here to present today on behalf of a group of generators who I think in the great mix and contemplation of the SMD efforts --

MR. KELLY: Excuse me. Could you just check that your mike is on?

MR. ALCANTAR: It says it's on.

MR. KELLY: Maybe you could move it a little bit closer to your mouth.

MR. ALCANTAR: If I get it any closer I'll be --

MR. KELLY: That's great. Thank you.

MR. ALCANTAR: The concerns we're raising today are over a group of generators who are generators within control areas in the West, but they are not generators on the system. They are generators and operators of facilities that are essentially customers. They are load-based resources. And they have been installed to supply or to address load-based needs. Typically these are ones that 25 years ago this Commission served as a flagship for supporting this particular development in the industry.

Do we need to work on audio again.

MR. KELLY: I'm going to trust that the audio people will correct the problem as we move ahead.

MR. ALCANTAR: All right.

MR. KELLY: And that if they don't, that Sarah McKinley will see that they do. Thank you. Please continue.

MR. ALCANTAR: Many of the speakers on the former panel and I'm sure on subsequent panels today will be addressing the wide range of questions you have asked, and the reason I think that we are somewhat unique and different in this process is that we're talking about a group of generators who really have been, if you will, somewhat left in the gap in terms of what you have evaluated, what you have presented as SMD rules that clearly make perfect sense for a merchant generator, for a utility generator, but have little applicability and in fact disastrous effects, I submit to you, for generators who are, as we call them, customer generators.

Customer generators fall into a mode where they are cogenerators, renewable resources, fuel cells, any form of generation that is serving customer needs first, not necessarily the electrical needs of a particular host, but the thermal needs of a particular host first. And so the secondary effects of their operation, their choices, the nature of their business happens to be electrical production, but it's a secondary feature.

As a result, they are not generators that are dedicated to the system grid. They're not there to try and figure out how to match loads. They're there to meet their industrial process, and as a beneficial byproduct of a highly efficient system, a highly cost effective system and one that for conservation reasons was and continues to be a vital source of supply in the United States, needs to be sustained and maintained.

What's wrong? What's the problem? As we start looking at resource supply and resource adequacy, the last thing you want to do is send signals to discourage units that are currently interconnected to the system to stay on the system or to discourage units that might be developed at customer generation sites from coming onto the system, and why are there discouraging suggestions in the air today.

Well, many of the rules that SMD contemplates, either what the definition of a load-serving entity is, I don't know yet whether a customer generator is or isn't one of those. I hope not. But I don't know. There's a lack of clarity and precision in the rule, and the concern over these particular entities that do not dedicate their services to the grid as a generator but dedicate their operations to say serving the thermal needs of a refinery is perhaps the best example that we have, a refinery manager is concerned with process steam. He's concerned with the safety of his operation and sustaining steam supplies to continue his process.

He doesn't operate when a dispatcher, say, from an electric system calls up and says, you know what, we need less power out of your plant; turn your steam generator off. That doesn't work and it hasn't worked for 25 years since PRPA came into being, and those units have operated and relied upon that sustained regulatory treatment for those operations.

Where do we go next? How do we solve those issues? To some extent, it's enforcing the rules you already have, and grafting them into the SMD concepts that you have. SMD, in many respects, not all, as certainly you're going to hear and I agree with, not in all respects fits for the merchant or utility generation supplier on the grid, those that are interconnected.

But it certainly doesn't fit and they do not work for units like we're talking about with respect to customer generation operations. Those units need to be treated as must-take resources; they need to be able to have a stable and secure contractual relationship to continue to develop and provide their power, and they need to have assurances that when they connect to the grid, they are being treated fairly with respect to the net delivery of their resources, and not being treated, as has been suggested in some regions today, that their generation is always dedicated onto the system and their load is always taken off.

The anomaly of that situation means that I have to schedule my power from my own generating unit out onto the grid to get it back to my own load, which just violates the very premise upon which these units were built.

What really gets screwy is, I get to play loss --

I appreciate the indulgence, but these are the points that I wanted to try and make. We have a distinct feature with respect to these generators and they need to be recognized and distinguished from your other rules. Thank you for the opportunity.

MR. KELLY: Thank you very much. Next is Kieren Connolly, Public Utilities Specialist, Bonneville Power Administration.

MR. CONNOLLY: Bonneville agrees with the Commission's statements in the SMD NOPR that generation adequacy is key to maintaining reliability and efficiency on the grid. As the Commission notes, electricity is often an essential service.

Bonneville also agrees that any independent transmission provider role in resource adequacy should be in support of existing institutions, rather than preemptive. And that's really the main point of my comments here.

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 authorized the Northwest Power

Planning Council, and Council develops a 20-year electric power plan to provide adequate and reliable energy at the lowest economic and environmental cost to the Pacific Northwest.

Congress directed Bonneville to act consistent with this plan, and so Bonneville is very concerned that whatever resource adequacy we move forward with under SMD works with what Bonneville is required to do under the Act.

As to the particular design elements and questions that the Commission asks in the NOPR, Bonneville generally suggests that the Commission should defer to existing regional institutions.

Bonneville's comments on these issues are preliminary since Northwest regional stakeholders are in the process of developing a market design for RTO West that will necessarily interact with these resource adequacy requirements, and because the Planning Council and other regional stakeholders are still in discussions on the applicability of particulars of resource adequacy as proposed under the NOPR.

I would note, however, that because the Northwest is predominantly hydro -- and the Commission has heard plenty about this before -- that there are reasons that resource adequacy may need to be dealt with differently in the Northwest, because we don't plan to a capacity standard in the Northwest; we're an energy-limited system, whereas our neighbors in the Southwest and in California may want to continue to plan to capacity standards.

MR. KELLY: Thank you. We're trying to fix the feedback problem. To tell you what I think we're going to try is, we're going to turn this volume down, so it's not so bad, and move the microphone for Peter Evans, closer to Peter Evans's speakerphone so that we can pick him up without this exaggerated volume. Maybe John Meyer, if you could simply move that speaker -- I'm sorry, the mike, great, down closer to the speakerphone, then we'll be able to hear Mr. Evans at a much lower volume throughout the room. We're trying to turn that volume down now in the AV Center. So we'll see if that works. Thanks.

Our next speaker on our list is Peter Evans, President, New Power Technology, on behalf of the Silicon Valley Manufacturers Group, via telephone. Mr. Evans, say a few words as a test, see if we get you.

MR. EVANS: Okay, can you hear me now.

(Audio feedback.)

MR. KELLY: Try it again.

MR. EVANS: How about now?

MR. KELLY: Good.

MR. EVANS: That sounds better.

MR. KELLY: You're up. Thank you for

participating.

MR. EVANS (Via Telephone): Okay, well, thank you for including us. By way of some introduction, Silicon Valley Manufacturing Group is a group of electric power customers in Silicon Valley and represents 190 of Silicon Valley's most respected employers, and nearly 275,000 jobs.

7

And the Silicon Valley Manufacturing Group currently addresses -- sorry. I'm hearing a delay back through the phone, so I'm trying to figure out how to not listen to myself.

The Manufacturing has activities in five core areas: Affordable housing, comprehensive transportation and reliable energy, quality education, and a sustainable environment.

The Silicon Valley Manufacturing Group has a standing energy committee and I'm really speaking on behalf of that committee.

With respect to the standard market design and resource adequacy, obviously we believe that resource adequacy is fundamental to the interests of our member companies and our objectives of fairly priced, reliable power, and we support FERC's efforts in this area.

We'd like to express a concern, however, from a customer's perspective, that regulations intended to ensure resource adequacy, in fact, end up placing additional risks and costs on customers, and restrict customer choice.

In California, if we have learned anything from rate-based utility generation, QF mandates, and now DWR contracts, it should be that centralized resource planning results in stranded costs that must be borne by customers. We've also learned that until these costs are recovered, customers are prevented from seeking alternative energy supplies that may better meet their needs.

Utility industry restructuring rightly places the risk of new generation development with developers who can manage it, rather than customers who cannot. We believe this feature of restructuring should not be abandoned.

The risks associated with resource commitments made in response to regulatory requirements are ultimately borne by customers. Too strong incentives for load-serving entities to make resource commitments in the name of resource adequacy will result in out-of-market costs that prevent customers from seeking competitive energy supply alternatives that meet their needs.

We suggest that the independent transmission provider resource adequacy assessment should be advisory, and load-serving entity term resource procurements should be limited to relatively short-term, except where end-use customers have made long-term purchase commitments.

(Pause.)

MR. KELLY: Does that conclude your statement?

MR. EVANS: That concludes my statement.

MR. KELLY: Thank you very much.

MR. EVANS: I can barely hear myself.

MR. KELLY: We hear you just fine here now.

MR. EVANS: Okay.

MR. KELLY: Our next speaker is Kellan L. Fluckiger, Senior Advisor to the Chair and CEO, California Consumer Power and Conservation Financing Authority.

MR. FLUCKIGER: Thank you, Kevin, and other staff members and the Commission that has allowed me the opportunity to speak today.

There is no question that we need adequate resources; the real question is, how are we going to decide how that is done and who is going to get that done?

In my mind, after listening to the panel this morning and one of the questions you asked, there is not anywhere near enough similarity in regions to mandate a nationwide approach to capacity. There is no question that the California experiment has had some severe problems.

To fix that and to move forward, everyone needs to focus, in my mind, on what they should be doing, and not grow the size and scope of the experiment. States are responsible for resource planning.

California at this point is now doing that in the form of orders from its Commission, and the Power Authority rulemaking and other things. They are moving forward, taking care of that resource adequacy requirement. It did not before, during the difficult stages of this, but it now is, and I don't think it would be helpful to confuse or muddle the process with additional requirements.

States actually, in my mind, have more incentive to avoid outages and wild prices than even the Commission does, because they bear the local and most severe consequences for those anomalies.

In terms of the actual responsibilities of different entities, the ISO runs the grid. There's no question that it needs information, and it needs it about what is going to be operating in the loads, but information is what it needs. And it should not create a scheme that says you must buy from me in any of its auctions or markets, but if you buy from me, here are the rules.

FERC regulates transmission. It should do so through its open access tariffs and proceedings. In my mind, to stretch that requirement to mandating capacity as a term of open access, is not consistent with its assignment and is an overreach. In fact, its assignment is to regulate power sellers and it should do so.

California, of course, has suffered the

difficulty of the last couple of years that it's still digging itself out from under, but I think FERC, in terms of taking its assignment, as California is, is focus on the regulation of sellers, focus on the regulation of just and reasonable rates in the power seller market. So everyone needs to do, in my mind, the best with the job that they already have.

There is no question that we need long-term contracts. In my mind, the FERC, in its effort, should make it easy to have that happen, but not mandatory.

There's no question that we need demand response. The lessons that I take, at least, from the past are the following:

We should not put structures in place that act as if demand response and other features are in place before they are. When we create markets that depend on certain things that are not yet there, they fail.

In my mind, we also have learned that nothing gets built without long-term contracts, very little is continuing to be built on spec, and we need to understand and recognize that.

I think that the creation of markets by an ISO or an ITP in terms of the capacity, should be a voluntary thing, if a region desires it, but the Commission should give deference to the region.

Specifically, what should the rule say? It should say that sellers report their contracted capacity to their ITP, and their remaining capacity, so that the ITP knows what's going on, what's sold, what's not, what's like to be available.

Buyers should report information to the ITP about what's contracted, so they know, so the ITP knows what its future is likely to look like.

The order should facilitate long-term contracting; it should recognize that all resources are not similarly situated, specifically, intermittent resources, demand resources, they're not the same, and creating a mechanism that treats them the same will harm them and make it difficult for them to happen.

The last point is -- or the last two points: The ladder approach, which is how you've referred to it, in my mind, is the only reasonable way to think about capacity. With direct access changing and with rules changing, trying to do something a number of years out that is fixed, will make it impossible and considerably more expensive.

The order should focus on oversight and investigation, as the Commission has now begun to do. That should be a very vigorous activity, and the last thing is to -- that the trend -- I heard it discussed on the panel this morning, and so I'm going to emphasize this -- the transmission business is the business that should see all costs related to delivery.

That is the only way, in my mind, to turn the signals generated about transmission into a business interest or enterprise. All the transmission signals, including congestion, should go to the transmission entity.

Those are the things that I think should be contained in the order that FERC focuses on. Some of them are a little bit outside the scope of capacity, but that's -- thank you very much.

MR. KELLY: Thank you. John Meyer, Vice President of Assert Commercialization, Reliant Resources.

MR. MEYER: Thank you. I appreciate the opportunity to speak before FERC on what I believe is one of the three most important requirements that should be in SMD to provide a reliable and robust wholesale market.

Today I want to address two things: The key component of the resource adequacy plan, and a proposal that Reliant has, what it involves.

There are seven key components I have identified that I think are a must, if you're going to have a good resource adequacy requirement. First of all, resources that can be counted toward that capacity -- and I use resources broadly in demand and generation -- must be contractually committed to the LSE or the ITP.

The requirement should be forward-looking several years, consistent with new entry; it removes the barriers to new entry for market power concerns in the market, and it allows time to build capacity or develop response programs if a shortage is identified.

It also must allow generation and demand to participate -- all generation demand to participate, otherwise, we talked about old gas, new gas, and we could talk about a lot of other scenarios where we've made market mistakes or regulation mistakes trying to use the same thing and distinguishing somehow differently.

It needs to be enforceable in a manner to ensure that resources are obtained for reliability needs, and that can easily be accomplished through a residual or full option, and we're not opposed, really, to either, though we have identified self-arrangement as a good thing.

The fifth thing is that it needs to be backed by actual resources, generation or demand. It must be better scheduled in the day-ahead markets, and be willing to be committed by the ITP.

Six, all resources should be utilized in the adequacy requirement, and they must be capable of deliverability during the peak periods on which the requirement is based. And, lastly, number seven, it should accommodate retail access programs.

Now quickly into Reliant's proposal, we believe the ITP should establish the annual requirement amount in conjunction with a regional state advisory committee, approximately three years forward. LSE's could self-supply on an annual basis, or receive an allocation through the residual option.

The ITP should procure the residual capacity through an open auction process. Those auction costs will be allocated to LSEs that did not self-supply totally, based on their load ratio share.

We believe existing generation, planned generation, or demand or contract rights based on specific generation identification, all qualify for resource adequacy, if they can prove deliverability.

Existing generators, this gets into the controversial piece -- existing generators tied to the ITP transmission network must offer into the auction, if not already committed, either bilaterally or through self-supply, and that could be in that region or another.

All resources selected for the resource adequacy, either through the auction or self-supply, must offer uncommitted capacity into the day-ahead energy and ancillary services markets.

Generation sold off-system by the selected resources through the auction or self-supply is recallable, if needed by the ITP.

And, lastly, generators should get paid monthly after they actually make their units available, including a review of whether they made their commitments by bidding into the day-ahead markets. I will stop there, thank you.

MR. KELLY: Thank you. Charles Reinhold is the WestConnect RTO manager.

MR. REINHOLD: Thank you, Kevin. It's a pleasure to be here today. WestConnect does encompass primarily the states of Arizona and New Mexico, and I'd like to thank Ron Lukas for leaving me time to comment about New Mexico today. That makes it a little easier.

WestConnect also may be able to expand its operations into the Colorado and Wyoming area, once we've resolved some of the jurisdictional issues and are able to bring some of the non-jurisdictional entities into our table as well.

The retail access experiments within the areas served by WestConnect, are really on hold at this point. In fact, some of the states are actively backing away from creating an open access environment within those states.

As such, the load-serving entities within our region continue to have an obligation to supply their end-use customers, and their obligation stems from a variety of regulatory authorities. It's not only states; we have local regulation as well as some additional federal and other regulation as well.

Additionally, in the west connect area, we have a very strong bias toward self-supply of resources and bilateral contracts not only in this capacity obligation market but as well as in general energy markets.

We also have a history of coordinated reserve sharing arrangements within the region. Some of those certainly have run into problems with transportation issues surrounding them, but in large part those arrangements reflected both the resource diversity that we have in the region as well as the seasonal load diversity that we see. We simply have some systems that are strong winter peakers as well as summer peakers so there are some diversities and some resources that can be recognized through that process.

I think those reserve-sharing arrangements can be reconsidered. They certainly need to take a longer look at the planning aspects. They were keyed more towards real time operations, but the longer term planning requirements I think will need to be developed.

In that regard, I would strongly FERC to allow regional diversity and the development of capacity obligations. And in this particular case, I would define regions as smaller than the entire western interconnection. I believe that there are differences that even SGWE cannot and probably should not address within the capacity obligations.

FERC's role I think would be a backstop role. And I think that backstop would be put into effect when the capacity obligations of the load serving entities are not being met

And last of all, because of the bundled retailed nature that we have in the area, we don't think that an independent market is necessary for capacity. We believe that the RTO in that area should be a little lighter, a little leaner, and that if capacity markets need to be developed, they would be developed in some other manner. Thank you.

MR. KELLY: Thank you.

And our last panelist is Gary Stern, Director of Market Monitoring Analysis for the Southern California Edison Company.

MR. STERN: Good afternoon, I guess. I appreciate the opportunity to speak with you today.

Edison supports the imposition of a capacity requirement on load-serving entities. An LSE obligation is the appropriate mechanism to ensure adequate supply. Capacity requirements lead to long-term contracts. Long-term contracts lead to the financing of new generation investment.

Capacity obligations though need to be applied to all LSEs to avoid reliability free riding. And this is a difficult problem because there may not really exist the appropriate regulatory body to deal with all the LSEs in the market when you consider municipal entities, IOUs, energy service providers, and it's a problem that I haven't really heard any adequate solutions for because of the jurisdictional issues.

But FERC should establish a minimum reserve requirement as proposed in the SMD NOPR. That's not to say that they should order the creation of any ISO-run capacity markets in all regions anyway. I really don't think such an ordered market in California would work at all as some have suggested. There's no demand curve for this so-called market. I mean, as an economist, I have difficulty calling it a market when there isn't a demand curve.

And in a region like California where we start out short, market power is clearly a present and a problem, and so the creation of an ordered market where, you know, if we can't self-supply or haven't self-supplied the ISO will buy for us, is one that I just don't think works.

To the extent that state reserve requirements exceed what FERCs SMD sort of minimal requirements that they'd put in place would be and I don't think a jurisdictional conflict exists because under those situations, the bind against is in the state.

It resides within the state, it resides within the state which regulates most of the LSEs anyway and I don't think FERC would have a problem with letting the states satisfy the resource requirement in their own way, as long as it's satisfied.

The goal here shouldn't be the creation of a capacity market. It sure be assuring resource adequacy. Finding a mechanism by which we can see investment in new generation to meet the reliability needs of our customers.

Capacity reserve requirements are long-term requirements and are not to be confused with the short-term ISO operational needs. Non-compliance with LSEs should be addressed at the planning stages and not in real time as LSEs may not control the resources to meet the requirement. In the case of California, as much as 40 percent of the power that the large LSEs have, is contracted power for which they don't have control of the resources. So if the resources fail to deliver in real time and a penalty is applied to the IOUs, it's not going to do any good. We don't operate the steel that the ISO needs to keep the grid running and therefore we are not the appropriate body to penalize.

And with that, I thank you again for the opportunity to speak this afternoon.

MR. KELLY: Thank you. As with the prior panel, we'll ask some questions, if someone would like to speak, if you would turn your name tent up, then I'll try to take you in order. For Mr. Evans on the speaker phone, if you'd like to speak, if you could just say "Peter Evans has a comment," I will try to note when you say that and take you in order also."

MR. EVANS: Okay.

MR. KELLY: Great. Alice Fernandez is going to begin the questioning.

MS. FERNANDEZ: Actually I think I'd like to start sort of stepping back. And that's sort of asking the panelists do you think there currently are adequate resources in the west? Is it something where there are adequate resources in parts of the west and not in others? Do you think sufficient resources are being added in the west based on sort of the anticipated load growth?

MR. KELLY: Mr. Meyer:

MR. MEYER: To answer your question, Alice, I think there could be adequate resources in the west, if you're looking at a forward-looking requirement, and we sent the right price signal that they will be compensated appropriately. If you're asking are there right now under various weather conditions, probably not.

MR. KELLY: Peter Evans has a comment at some point. Mr. Evans, I've heard you and you'll be the fourth person to speak.

MR. EVANS: All right, thanks.

MR. RHEINHOLD: We can't look at the entire west in this equation. I think the resource adequacy on a long-term basis needs to be looked at regionally. We've heard certainly in the northwest that capacity is not an issue but from year to year, there may not be enough energy to actually utilize the capacity that's available within the hydro system. In the Arizona/New Mexico area we have had this serendipitous experience of having a great deal of generation installed within the state.

I think it's more that we're close to California but still outside the borders rather than the needs of Arizona that drives that, but nevertheless the Southwest area as served by West Connect seems at this point to have a large supply, in fact, potentially an oversupply of capacity. We need to find a way to get rid of the boom/bust cycle. This is going I think, in my mind, to drive folks not to install capacity and that may become a problem in the long run for the load growth in within the West Connect area.

But the message is, I think we need to look at smaller regions, not the entire west.

MR. KELLY: All right. We're going to go to Mr. Fluckiger and then Mr. Connolly, Mr. Evans. I don't know that we intended to go half our time on this one question, so if you could keep your answers brief, i would help us.

MR. FLUCKIGER: Very brief. That's a good question and thinking about it as one market is appropriate in some circumstances and not in others because there are numerous transmission constraints. So you have to look at it in smaller areas. So speaking for the California area I don't believe and it is partly seasonally dependent and rain and other things, I do not believe there are sufficient resources, and that gives rise to the two concerns that I mentioned; one is about things don't get built without contracts, and making that easy should be a focus, and the second concern is the transmission and deliverability.

MR. KELLY: Could I follow up on that. You said in your opening statement, states are responsible for resource planning and no additional requirement is needed. I'm paraphrasing. And yet you just indicated that California is dependent on other states for its resources. What do I conclude from that? That there's no interstate role for FERC or that the arrangement with other states in the west will do the planning, or help me reconcile those statements.

MR. FLUCKIGER: You bet. California has a number of resources that are participant resources that are located out of state. Shirley talked about those. And for many years California has built interties and imported; there's been a lot of seasonal exchange between the Northwest and California. So creating enough steel in California to serve California is not necessarily a goal that I think is appropriate or that we're aiming for. Appropriate resources at he lowest cost, done by the appropriate entity, etc., etc. is the goal.

So I'm not trying to say we're going to have enough of California to cut it off and make it an island because then we'd lose seasonal diversity in exchange and those kinds of things that are beneficial.

MR. KELLY: Thank you.

Mr. Connolly

MR. CONNOLLY: In the Northwest, I think we have plenty of capacity. Our problem is energy, as I mentioned earlier, and we are just now in the last few years, I think, beginning to try to bring the transmission constraint question into the planning equation and that's probably where we have some problems today.

We also see that the Northwest does continue to grow and in the future we will have resource issues and we will have to deal with them.

MR. KELLY: Okay, Mr. Evans?

MR. EVANS: Okay, thank you. First of all, I can't respond to the question directly, but I think that the question illustrates a shortcoming of the notion of a capacity requirement. Clearly in California, there's been a lot of resources added and everybody will note for the most part those resources were added based on the developers assessment of the capacity requirements or the capacity shortfalls market in the late 1990s with is a process which we applaud, but there clearly remain local constraints.

Silicon Valley's one of them. We think that a notion of a capacity requirement doesn't allow you really to get to those local constraints and those are of greater issue to end use customers.

We also have the sort of interesting irony that from a customer's standpoint in California, there's too many resources and that is that resources that have been secured on behalf of these customers now prevent them from pursuing non-utility alternatives.

MS. FERNANDEZ: Let me see if I can clarify that. Is your answer than that you think that maybe overall on the West there are adequate resources but because of transmission constraints some of those resources in certain areas there's a sufficient amount of resources that are deliverable to the load?

MR. EVANS: Or that the capacity's in the wrong place.

MS. FERNANDEZ: Okay, but it's the resources can't be used by the load in some areas where the load either needs additional resources would need to be constructed or additional transmission would need to be constructed to bring the resources that exist in the West to that area.

MR. EVANS: That's correct. And if you have a regional capacity requirement, it doesn't allow you to see those types of dynamics.

MR. HEGERLE: So does something like the Path 15 Project that's going on solve some of those problems?

MR. EVANS: Well, Kevin would know the answer to that question better than I would. My personal feeling is that it probably doesn't. It certainly doesn't contribute to any capacity shortfall in Silicon Valley. But if you have a capacity requirement for California, for example, that wouldn't help you understand the local issues like Fresno, and San Francisco, and the Greater Bay Area whether those issues are really being addressed.

MR. STERN: Just to add there are a number of load pockets in California, Path 15 is certainly a critical issue and has been for many years, but there are San Diego, San Francisco, Fresno, Humbolt, Silicon Valley, there are a number transmission constrained areas that fall under the problem he described.

MR. KELLY: So is that something we should expect to see come on line quickly, or is there opposition to that, or?

MR. EVANS: Getting new generation to San Francisco is a horrendous problem. It has been forever. I don't have a ready solution to that, and there've been a number of projects proposed. One of the things that I think has to be thought about is we have to meld reality with goals. And so San Francisco lights stay on but they stay on under a particular regime. Generation's old, it ought to be replaced. It's dirty, it ought to be replaced. But getting that done has proposed some challenges and I don't think a new rule is going to get over that problem.

MR. BANDERA: And just to stand on that a little bit, at the same time that those problems exist that Kellan described, customer-owned generation is being penalized so that recedes as an alternative and could actually be a big part of the solution in places like San Francisco and Silicon Valley, and demand response, at least in our view, really hasn't been pursued to the extent that it could be.

MR. KELLY: Mr. Stern has been waiting patiently. Give us your views.

MR. STERN: There may be sufficient capacity right now for California but certainly within a short period of time without additional building there won't be. What we know already right now is there isn't adequate resources, contracted or built by each of the LSEs to meet any particular requirement because we come from an environment where we didn't have such requirements for the past several years.

So one thing we have to recognize is as we consider the imposition of these requirements as we're going from a situation in which the large LSEs may be coming from a 90 percent of peak situation to the 112 percent that's being contemplated, and we need some sort of a transition plan to get from here to there, because unlike most if not all other areas of the country, we're not starting from a situation of an existing requirement that's simply being modified; we're starting from a situation now where no requirement exists and therefore insufficient load serving entity resource adequacies is the current state.

MR. KELLY: Kellan, I want to get back to your proposal that you outlined earlier. You suggested and clarify me and how I may be misstating it, that the primary mechanism shall be that LSEs are responsible on their own for procuring adequate resources and that the only formal mechanism should be a requirement by buyers to indicate, I imagine to the ITP, what it has procured, and for sellers to indicate what it has sold in the future. And that would be the primary resource mechanism to ensure adequacies.

Is that correct?

MR. FLUCKIGER: The information to the ISO is for their use to understand about reliability in running the grid. That has no bearing on assuring adequacy and I understand that. What I did say was that the regulatory authority that regulates the utility and has historically regulated the utility, whether it's municipal or the IOUs. is the one who has fulfilled that job historically. We had a break in that with the restructuring process. That's been changed. And that is still moving forward.

So my concern is conflicting requirements and incompatible requirements and then a real possibility if you think about a requirement that you might impose that the ITP then is going to second guess, read contracts, decide what their worth, you know, enter into a whole regime that is, in my mind, beyond the scope of what is necessary and I reiterate what I said before. I think the local regulator has more incentive or at least as much incentive to keep the lights on and keep the prices reasonable as you do.

And so I don't think we need to do it twice.

MR. KELLY: Let me just follow up on that. You said in your opening statement, FERC regulates transmission and you can't stretch this to include resource adequacy but your very next sentence was FERC should focus on just and reasonable rates in the power market. Now there's sort of an odd situation where if you actually have a market where the price is set by supply and demand, and FERC has no control over supply and no control over demand but we're responsible for where the supply and demand curves cross, that kind of puts us in a pretty awkward situation for dealing with that.

Is there something that you think FERC should do to see that in the long run, resources are adequate. Even if we do something that's done in a very state-friendly way, retaining a strong state role in defining and implementing the needed level of resources, but that there would be some interstate FERC requirements so that -- well, I mean we clearly saw that when resources are short in one or more states in the West, that all states end up having in the West rate cases for dealing with the consequences, is there a role for FERC to dealing with the interstate aspects of sales for resale power prices that result from short resources and should we therefore do something about short resources, however minimal it may be.

MR. FLUCKIGER: I should have taken notes on the question. There were several in there.

MR. KELLY: Yes, sorry, I was rambling a little bit.

MR. FLUCKIGER: I'll do the best I can. My initial statement was that yes, you do transmission. That's fine. You do regulate sellers and that needs to be a focus of what you do. Imposing a requirement on buyers to buy, it is just as logical to impose a requirement on sellers to sell or build, and so I don't understand the single-sided sort of approach to that in the first place.

But I think that the local regulatory authority is in charge of obviously deciding how much they're going to forward contract, contract long-term, get resources built, approve rates, and so forth to management that, and every one each individual utility decides how much they want to expose themselves to a spot market.

So creating spot market rules that are fair, reasonable and correct is something that in the wholesale side that you do and should do. Each entity could decide and should decide how much these choose to use that market and that's what I said to start with. It shouldn't ever be that you require someone to buy but if you buy from me, and I'm speaking as if I were an ITP, if you buy from me, here are the rules and here is the process, and then everyone can decide how much they want to participate in that or not. And if those requirements are kept very small, because people do a lot of forward contracting, and that sort of thing, and demand side develops and that kind of approach, which I think is appropriate, then the spot market being small can send some signals and can be small enough that it's not going to have the drastic impact that we had before.

I know I didn't answer all your questions but that's all the ones I can remember.

MR. KELLY: Thank you. Mr. Meyer, and then Mr. Alcantar.

MR. MEYER: I just have a couple of comments on the key components that I had mentioned earlier and first of all, we've heard about energy being a problem associated with the hydro. It's obviously a problem with intermittent resources. And one of the key issues is the capacity that is allowed to fulfill an obligation of resource adequacy has to be available when it's needed, and if you're setting up the peak demand period, it has to be available at peak,

The other key thing here, the resource should be under contract if you're going to count it, and therefore, if it's under contract, even if it's not available, it will be able to substitute and find other sources to meet that obligation.

I guess lastly, and Kellen, you've already hit this point several times, is I can't understand how free source adequacy is dependent on other state resources. It's going to be state controlled. A single state control.

It's interstate commerce. And so I don't see how that can possibly be moved to a single state control.

MR. KELLY: Mr. Alcantar, you put your card down.

MR. ALCANTAR: I put it down just to be back in horizontal position. What I wanted to add to the point that you made, which I agree with, there are roles that at the very least you're in a difficult spot, but I think you also have affirmative duties and responsibilities certainly with respect to the just and reasonable standard for wholesale transactions in transmission or generation.

But specifically, when it comes to certain types of resources, you have enforcement resources with respect to provisions of your regulations to require the states to implement consistent with those regulations. So all I'm saying is it's you're a little bit pregnant. I don't see how you back away from this.

I understand Kellan's point where he's like many, desperately interested in retaining local control, and there ought to be certainly dramatic respect given to the kind of input that local control gives. That's the insight that we need. But you have duties and responsibilities ultimately as a final arbiter on many of these disputes and many of these issues, and they're coming your way, period.

MR. KELLY: Mr. Connolly?

MR. CONNOLLY: With regard to hydro and intermittent resources, I think it does come down to a reasonable question in that what is the problem you're trying to solve? We have no problem in the Northwest meeting peak load. It's whether or not we'll be able to meet load two months after the peak.

And so the very measure of resource adequacy may be different for us than it is elsewhere.

I would say, too, that with the Power Planning Council, we do have a multi-state entity in existence today, and that coordinates that resource adequacy across that region. I think the question that FERC has to answer is how do you ensure that, say, the Northwest and California are talking? Because our measurement may very well be different. And what we're trying to do to ensure adequacy for our region may be different. And I think that's the whole Western vision that the various RTOs in the West have been trying to work on is.

So how do we have our markets that meet our local needs but recognize that there are transactions that go across those borders?

MR. KELLY: Could I follow up? You said how do "you" -- looking at us -- ensure that the Northwest and California are talking? Were you suggesting that's a role for FERC, or was that a generic "you"? How does one -- I don't mean to just pick at the language, but I'm really;y trying to get at what FERC should do to help deal with Western resource adequacy than can only be done if there's something that can only be done by an agency responsible for interstate commerce, and what we shouldn't do?

MR. CONNOLLY: I guess I would say that we are working together within the region today in other areas to ensure that we do communicate with each other that we are not creating incompatible systems, and that for the most part, we've been fairly successful with those sorts of things in the past. And so that first deference should probably be given to letting the region figure it out for itselves.

MR. KELLY: Mr. Fluckiger?

MR. FLUCKIGER: The "should" and "shouldn't do" question is always interesting. One of the things that should happen I think, and that is your jurisdiction, is that sellers who have power market authority or authority to sell at market-based rates, need to be required as a part of that authority to participate and offer their capacity and energy in markets and auctions.

I agree with many of the things that John said in terms of how a capacity adequacy thing might be defined or measured. I would just have added the caveat of who does it and who imposes it behind many of the things that he said and not disagreed with many of them in terms of measurement and determining how they work. What it should do is sellers that get power marketing authorization and can sell and divest a generation question that Gary noted earlier, they need to be required to offer capacity and to offer energy.

And so that is an appropriate role for you. And to assure that that's done at just and reasonable rates and not rates that make them go out of business, and also not rates that impose the significant burdens that we've seen on not just California, as you observed, but an entire broken Western market.

One of the things that I don't think you should do is expand the regulations to directing buyers, because that creates the kinds of conflicts that I think can make the utilities in a difficult position when they feel like they have more than one master for the same subject.

MR. KELLY: We're going to go Mr. Reinhold. Mr. Connolly, is your card still up? And then Mr. Meyer.

MR. REINHOLD: Back on your point of how does FERC keep involved within the process and coordinate, I think your state outreach program provides you with an opportunity to have information from the states on how they are dealing with this issue.

And in similarity to Kellan's analogy that the RTO needs information about resource adequacy for its own operational purposes, that information I think provides the Commission with notification when it needs to start stepping in, whether you can sit on the bench or whether you need to start warming up because you're about to go int he game. I think you need to keep that effort up.

But I think that is your primary role at this point in the West.

MR. KELLY: Can I follow up on that? In your opening statement, you urged FERC to allow regional diversity. And that could either mean leave us alone, or it could mean have some requirements but within those requirements, permit regional diversity.

I just wanted to see which you were getting at.

MR. REINHOLD: I think some minimal requirements are certainly allowable and acceptable. I would not like to see a single requirement imposed over the entire West, for instance, nor would I like to see it imposed over the entire country.

I think there needs to be room for creative arrangements to be made. Certainly some areas may be better than others at working together and sharing the resources that are needed or coming up with ways to make sure they're online on time.

But I think your role in those areas where you choose to allow that to happen should be certainly active monitoring of what is going on and dialogue with the local regulatory authorities that are responsible for the actual requirements.

MR. KELLY: Just one other follow up. I think I've been hanging around lawyers long enough I'm starting to think like one. You said something like let the West and the states work it out, and then if it doesn't work, FERC should step in.

The FERC eventually steps in. That implies we have some authority and jurisdiction to step in. And the lawyers would say then why didn't we step in in the first instance if it's something jurisdictional to us? I think you actually had the disadvantage of getting a law degree at one time, so I might ask you that question.

MR. REINHOLD: That cold be a disadvantage. Frankly, I would rather that you and the other regulatory authorities work out the jurisdictional issue yourselves. From our perspective or my perspective is implementing and operating an RTO, I'm concerned that there are requirements there. I'm not necessarily concerned on who has the authority at any given point in time.

MR. KELLY: Thank you. Mr. Meyer?

MR. MEYER: I have a couple of comments and a question for Kellan. One of the things we didn't talk too much about, and it's kind of been hinted all along are the needs.

And I guess we feel besides those needs that are mentioned in the NOPR itself, which spot markets don't give timely price signals and the mitigation dampens the price signal and there are free riders, so you need an adequacy requirement, the mitigation in many of the areas now are causing marginal generating units not to be able to recover their cost as well as other I'd say low capacity factor units.

And this is basically their fixed costs to run. Some of that is caused by mitigation in the total market through amp or mitigation in local type congestion issues.

Having said that, someone has to look at the public good, whether it's good or bad, whether we make sure they stay there if we don't need them obviously in a real market world, they go away. And is that going to hurt or help people?

What we had hoped that the real need of the adequacy requirement is, it allows or makes sure the ITP has sufficient bids, or he has the ability to have sufficient bids available in the day ahead, the real time and ancillary service markets, such that we allow him or our side to purchase or designate as much adequacy insurance as they want.

However, when they do that, that means that those are the generators that are going to be supplying or mandated to supply all t hose bids or basically;y complete a must-offer requirement.

Now the question I have for Kellan, he said that he believes sellers under market-based rates should be forced to offer capacity and energy. And we actually;y have in our proposal that all sellers or all generators and suppliers have to offer capacity into the auction. In our case, we have a residual auction -- to the market of their preference.

In other words, they could offer it in the market they're in or they could offer it in another market, but they have to have offered it.

And to us, I guess the question is, if the ITP has adequate resources, they're the ones to supply the energy, why should everybody else have to be forced to then supply or bid energy all the time also?

MR. FLUCKIGER: I guess I would respond to that in three ways. There's a long history in the West under the WSPP arrangement and others of people making sales across areas, Northwest, Southwest, California, wherever, to take advantage of seasonal diversity and efficiency.

Recently there's been a struggle with availability, capacity, and the same units are still there, and the loads aren't that much higher. I have to ask myself why. Why are we suddenly in more trouble than it looks like we ought to be? And I said earlier I don't think there's enough capacity, because some has been retired, I think there's a close call right now, but there needs to be more.

But what this says to me is, under the new regime, under the new vision, we actually need more capacity than under the old vision.

So that brings -- if you're going to say you don't actually have to produce from some of the existing capacity, because utilities built just enough to supply their customers and have reserves for outages and that sort of thing.

So if we're saying we don't have to use the existing capacity, we don't have any kind of requirement, then that tells me, I need more than I used to need so that there's enough. Because everybody doesn't really have to supply.

So you've either got to tie it up under contract, which is the replacement for owning generation now when it's divested, or you have to have more capacity than you used to have because you're not going to actually require everybody to participate, and you may need then more, or you're going to have to turn the lights out.

MR. MEYER: I think basically then your statement is that you offer the capacity and you should be taken if the market is capacity insufficient or level, whatever, and then you would have a must-offer requirement on the energy for sure.

MR. FLUCKIGER: I'll be really clear. Long-term contracting and shrinking the spot market is the way out of the mess. It gives us new resources. It assures capacity adequacy going forward, and it puts the spot market to a small enough size that it's not a danger and a menace to anybody.

So I clearly think that that's the way to do it. I don't have a perfect silver bullet about how to get the requirement together, and I've been really clear that I think that it state in its rulemaking and processes is moving in that direction to reinstitute that. And I understand that's the burning question here too. And I've said what I think about how that ought to be handled.

MR. KELLY: Before we move on to another topic, Mr. Evans, I didn't hear. You asked to speak. Do you have no comment on this?

MR. EVANS: I guess I'd better offer something. A lot of things going back and forth. I think I agree with what Kellan said that FERC's role in making sure that the markets work well and that the sellers who are operating under market-based rates, who are qualified to offer under market-based rates, are abiding by the rules is really important role.

And then also I think I agree with him that mandating buyer activity is maybe less important role, and I think that's consistent with our comments earlier that when buyers are mandated to make resource commitments, that turns into customer commitments and ultimately can restrict customer choice.

I think I'd disagree with what Kellan says that long-term contracts are required to ensure that new resources get built. I think a lot of people believe that's true. I come from the IPP business, and I think that we ought to try to make the market work if we can.

I think one way to deal with that perhaps is what she recommends is that let states decide on their own. The extent to which they want to rely on the spot market, rely on very long-term resource commitments or something in between.

I think everybody has stated that their regions are different and have different requirements, and I think that's one thing probably that's coming out of this discussion is that there isn't a one-size-fits-all approach, and perhaps what Kellan suggests, that is, to leave it to the states to decide and the utilities to decide, addresses both the jurisdictional question and also the regional diversity question.

MR. KELLY: With apologizes to Kellan, we wanted to move on and get a different line of questioning going. Alice?

MS. FERNANDEZ: I guess in a way I think it's somewhat related. I guess I'd like to try and get into what type principles should be in the final rule. I've heard a lot of interest from this panel in really relying primarily on state commissions, through state process for load-serving entities to ensure that they have adequate resources.

But I've also heard some interest in a FERC backstop. And I'm trying to figure out as to how you would enunciate these principles as to what is it that if there are certain state programs in place, certain regionwide, either the entire West or some parts of the West, that the state requirements would basically be all that's really needed, or at what point in time there would need to be some FERC role in this process.

MR. STERN: As I noted earlier, I think that FERC's recognition of the need for an adequacy requirement and load-serving entities is appropriate.

I think the states' recent recognition of the same thing is also appropriate. It does seem like the ultimate decision on how much should be added and related issues are best served if they can be done by the state, and therefore the backstop approach that I believe is in the NOPR as it's written now is appropriate.

You put out, assuming the definitions are consistent, and that it's not obvious that they are, a 12 percent requirement, which is from the perspective of reserve margins, a relatively low number. And that tells the state you've got to do something. You're probably not going to be satisfied with 12 percent or whatever the state is. And sure enough, in California, the PUC is currently talking about 15 percent. The CPA has been talking about 17 to 22 percent.

If any of these kinds of numbers are ultimately adopted, then the FERC standard will be met and everybody should be in relative agreement that we've dealt with resource adequacy and the state has been able to figure out how it wants to deal with resource adequacy in its way and FERC's requirement has been met.

So to me, the approach we've got out there now kind of says we're not going to allow a system to take place without any resource adequacy requirements at all is appropriate. And that's what FERC's done. I don't think they need to do more.

MR. KELLY: A quick, I hope, quick follow-up.

When I hear backstop, what I think of is if the state process fails, FERC would step in and failure would mean that we end up with inadequate resources.

Our proposal was to try to put something in place to get resources developed three or five or whatever number of years in advance of the failure. How does being a backstop fit in with that? Just in terms of timing. I guess Mr. Stern and maybe others could address that as we go down the row.

MR. STERN: If the states come through with the plans, in California's case, for instance, we have a requirement by April 1st of 2003 for at least the investor-owned utilities to put forth a resource plan at the PUC that is intended to meet a 15 percent reserve requirement that in fact the ISO should be participating in that process to make sure that it believes that what the state is putting in place as a plan is consistent in definitions and other things with its needs.

And if it is, then basically there ought to be a conclusion by FERC that its 12 percent requirement has been met and no further action is necessary. So the backstop in a sense is not a binding constraint.

If the state were come to come and say, well, you know what? We decided we only need 10 percent and we're just going to rely on our neighbors for the rest, in a sense free ride on the West, then FERC's 12 percent would not have been met, and whatever rules you ultimately would put in place to ensure the 12 percent is met would kick in.

And that's the sense in which I think the backstop plays a role.

MS. FERNANDEZ: Is it also something you could say perhaps not with a specific percentage, but I mean if the state resource planning ensures that, has a way of showing that the load-serving entities have sufficient resources without in effect calling on other ones, relying on other ones to provide it, that that should be sufficient?

MR. STERN: Yes. I think in a sense, 12 percent -- pick a number out there, and it was picked as a reserve margin. Some issues associated with definition and all that. In the end, yeah, the most logical thing is for the FERC to conclude that if the state comes up with its plan for resource adequacy requirements for the entities in its market, and FERC finds that satisfactory, then there isn't any issue that needs to be pursued further.

MR. EVANS: I guess I may have a question at some point or I may have a comment.

MR. KELLY: Peter Evans, did you say you wanted to speak?

MR. EVANS: Yes. When you get a chance.

MR. KELLY: You're actually next in line, so why don't you go now and then we'll go to Mr. Meyer afterwards.

MR. EVANS: Two thoughts on your question. The first is, somebody earlier pointed out that the objective is resource adequacy, not a particular reserve margin, and I think that's a good distinction to keep in mind.

But I wrote down two things that FERC could do. I wouldn't characterize them as a backstop, but I think they're very important to ensure resource adequacy without actually mandating a requirement.

One is to take measures that ensure open and transparent price signals both in the spot and forward markets, because volatility in the spot market and transparent prices in the forward markets are one of the big indicators for competitive wholesale generators as they assess market adequacy and where they think they want to invest.

And then the other thing is reliable load data from the load-serving entities, and some of the utilities represented here may not like that idea. But to the extent that load-serving entities aggregated load data is available then competitive wholesale generators can make their own assessments of where there are regional, in their case, opportunities or shortages if you're a regulator.

But they both accomplish the same thing, and that is a market mechanism that allows people to anticipate shortages and respond accordingly in the marketplace.

MR. KELLY: Mr. Meyer.

MR. MEYER: Okay, thank you. The question as to what should be in the final rule, I believe FERC got several things very correct, and very positive in their proposal:

First, that a requirement has to be forward-looking; it has to be deliverable, and it's asset-backed.

In addition, I think they impose the obligation or, I guess, the suggestion more, that the RSAC has the -- sets the planning period and reserve requirement. I think that should be together with the ITP, because I think they need a lot of input from the reliability -- the person charged or tagged with reliability in the region.

I don't think it quite goes far enough. I think the next step is that there has to be a way to enforce it, which assures adequacy, not penalizes when it doesn't happen in real time. And somebody, I think, has already pointed out why that does not work, trying to tie real-time to a three-year forward type approach.

If you're going to have penalties or you're going to have enforce that adequacy, that has to be done at the time the resources are required for the plan.

And I would suggest the correct way to do that still is that the ITP has the right to procure residual capacity through an open option.

That doesn't mean he's going to. If all LSCs cooperate and supply as set up by the state advisory committee and the ITP together, everybody should be happy and there's no residual option.

If they don't, however, he will assure adequacy, which I think is what you've tagged him in your various orders and rules, to be the person in charge of reliability.

And I don't think it works very easily on a state basis, unless a state or several states in a region, as pointed out by WestConnect, can demonstrate that they alone are adequate; they don't need resources outside of the region at all, and therefore they will only look inside, so other people have suggested that.

I'm not sure that's the best approach, as we have heard from the Northwest reserve sharing and other things that are very important, going across state lines and across regions. So, to blend it altogether, I believe it is the charge of FERC, when you have multiple states, multiple jurisdictions, and multiple regions, that you're trying to have a consistency in in an interconnected grid.

Having said that, that's my belief and what we need.

MR. KELLY: Thank you. Mr. Fluckiger?

MR. FLUCKIGER: I'm going to talk about something I haven't talked about very much, and that's about cost. If you put a forward requirement three years out where every LSE has got to prove that they've got a hundred in anything, three years from now, you're going to raise the cost, period.

And I don't think that's what we want to do with 888, 2000, and the principles expressed, and the reason is because we have had a good -- you can't get -- I can't -- I buy from Bonneville. I can't get him to commit three years or two years from now that he's going to have something available.

If I build my resource adequacy, you can say I need 70 percent long-term or 80 percent or something, but the load shape in California is that the last ten percent or 15 percent of the load only occurs one or two percent of the time.

It doesn't happen every summer and it doesn't happen every month of the summer, and so meeting that really sharp peak is way different in terms of capacity and other things. We share stuff. I might be able to buy something from him next week, and he can tell me, based on his water, I can sell you a month worth of stuff across peak next week, but he can't tell me that about next year or two years from now.

And I may not know I even need it until I see two weeks from now, a high pressure system building and we're going to have that needle peak, you know, two weeks from now. So I really struggle with thinking about that and the ladder approach that you talked about, in my mind, is the only way to make this work, whoever imposes the capacity requirement. And so 100 and X percent, three years out is not going to work, I don't think.

MR. BANDERA: Let me ask you a quick question: If a generator, let's say, needs to be built, and it's only being used one to two percent of the time, and it's not under any contracts, and it just is there on a speculative basis, that it may be needed because it doesn't think that some other entity has looked in advance enough and procured enough and it's sitting there for that one percent of the time, what type of cost recovery in the spot market should that generator have?

MR. FLUCKIGER: I said earlier -- and I'm going to try to be consistent with that -- I actually don't think we're going to build any more spec generators for quite awhile. I know that Mr. Evans disagreed with that, but I don't see evidence of that. I see them being cancelled all over the place, and things that are not under contract are not moving forward.

And so the answer to your question is, it needs a contract, and it needs a contract so that it will be there the one percent of the time, and have its capital recovery done.

MR. BANDERA: But if it's not -- so if this one percent of the time occurs, and a generator is sitting out there that isn't under contract, and is needed, how -- what type of price mitigation should be there in that case? That shouldn't happen, but if it does happen, what should happen?

MR. FLUCKIGER: You asked me what kind of price mitigation should be in place.

MR. BANDERA: Well, because -- yeah, what type of price cap should be in place, or should there be a price cap in place for this generator that exists that isn't contracted forward?

MR. FLUCKIGER: A business owner, my generation buddy here to my left, is going to tell me that if he doesn't get enough money during the year or years to keep his unit in service, he's going to shut it down, raise it, and put condos there, and that's probably what he ought to do, from a business perspective.

So, there has to be a mechanism so that the unit gets its appropriate recovery. You can do that through a contract that says I need you to be there. You can do it through a capacity payment to stand ready, you can do it through an uncapped energy market so we can charge $5,000 a megawatt for one minute. And we've seen that particular approach subject to another other consequences, particularly when combined with potential market power and other issues and market clearing prices and things spread all over the place.

So, the way that we handled that before was the unit was essentially under contract, either in utility rate base or whatever, and then it was called on to perform.

And so, in my mind, the contract is the way to do it, and if you don't, then you have to invent a way, and I don't think $5,000 prices is the way, not because it's not -- I understand the economics of it all. I just don't think that works in terms of the structure of this process, going forward.

MS. FERNANDEZ: Let me see if I clarify. Before we got into divestiture and the like, I'm sure that Mr. Stern, when he went before the state, probably had to show that one percent of the time that you still had adequate resources?

MR. STERN: What we used to have to do was show what reserve margin was necessary to achieve a level of reliability, and then show a plan that achieved that level of reserve margin. And one of the things that we have to note here is reserve margin here is somewhat being used in a shorthand form associated with reliability.

And to deal with a lot of the issues that we have been recently discussing, that the makeup of the system, whether it's hydro that varies a lot from year to year, based on precipitation, whether it's a very peaky load, whether it has a lot of high capacity factor resources or low capacity factor resources and the forced outages.

All those things should go into establishing for that load and that system, what level of reserve margin of those types of resources is necessary to achieve a level of reliability. And it's the reliability that's ultimately the target, and reserve margin is just our shorthand way of dealing with it.

MR. EVANS: This is Peter. I'd like to comment.

MR. KELLY: Peter, go ahead.

MR. EVANS: Just responding to Kellan's comments, which I for the most part agree with, first of all, providing resources -- and this is one of the shortcomings of reserve margin requirement -- is providing resources to meet load that is -- a load peak that occurs one percent of the time, before you have exhausted demand management opportunities is, in my mind, inefficient and ultimately results in additional costs for customers.

And I think most of our member companies would agree that that one percent of the time probably can accomplish much more cost-effectively through demand management. And if there is a demand response market, that's one of the ways to respond to reserve needs, operational or planning reserve needs, and that's one of the ways to address that.

I would also, just to clarify my earlier comment, if ultimately it's determined by what the state, in this case, or the system operator, if he's looking at an operational reserve need, that this needle peak, in fact, has to be met with hardware, with a piece of iron, and obviously the cost of that is going to have to be, because its revenue opportunity in the other two markets is very speculative.

It's cost would have to be recovered through some type of fixed cost recovery, and in my mind, that's exactly the problem; that if the cost of meeting a high level of reserves, planning reserves, particularly in a peaking market like the West or California, you'll end up with a lot of stuff sitting idle, and cost is ultimately borne by the customers.

MR. KELLY: I'd like to jump in with a comment here. We've talked about earlier, a lot of sort of deference to the West and the RTO and the states to do the planning.

One of the things that we've proposed in our rule is that there be a -- that all resources be treated neutrally, whether it's a demand-side resource, a transmission resource, a generation resource, distributive generation, renewables, that they would all have an equal opportunity to satisfy the resource adequacy requirement.

What if, in deferring to a region, there is a single-minded attention to meeting a reserve requirement to find as being just generation? Should -- that will result in higher costs for consumers in the wholesale market. Do we have some responsibility? Should we, in the final rule, lay down some principles that require all resources to be treated equally? That's for anybody who cares to answer. I know your cards are up with regard to the last question, but, Kellan, I saw your hand shoot up.

MR. EVANS: I'd like to comment also.

MR. FLUCKIGER: The Power Authority is focused very heavily on demand response, and I want to agree with something that Peter said as well. Demand, in my mind, has received woefully inadequate attention.

I think that I'm going to answer your question in two parts: One, resources are not equal, and so every -- absolutely it should be structured that demand can and should play a critical role.

We have to recognize that resources, different technologies of generation and demand, and demand doesn't exist to consume electricity. Generators exist to produce electricity. We can't treat demand like it exists to consume electricity.

We have to recognize the impact, the other peripheral impacts that are the major issue for demand programs. Having said that, we fully support the development of real-time pricing tariffs or similar things that pass signals on to load, and to, you know, get the demand equation involved in an appropriate way.

And so the rules should support that; it should recognize the difference of demand from generation in a significant way, so that they are treated equally, but recognize that they're not similarly situated, and so there is due discrimination in that, that's deserved in that case.

The second piece about demand -- and I will be really brief -- is, while I support it 100 percent and it is critical for achieving stability in the markets, we can't pretend that it's there more than it is. We need to develop rules that come into effect as the demand response is there, and not set a deadline and say we're going to shoot you if you haven't done this by this date.

Those things take time. It's public policy, and they develop over time. So, the rules come in as the demand develops, and it should develop.

MR. HEGERLE: Can I just ask where is California in real time, Peter, in tariffs?

MR. FLUCKIGER: There is a proceeding right now that was opened several months ago at the Public Utilities Commission on alternative pricing tariffs, critical peak pricing, demand programs, and so forth, exploring that, so that's an active proceeding underway.

There are a number of proposals in that proceeding, including critical peak pricing and some others to look at. Whether it's large groups, small groups, select groups, pilot groups, mandatory, but some kind of moving forward in the pricing, so that's the PUC. The Energy Commission has supported that for a long time. The Power Authority, in its investment resource plan, believes that there are thousands of megawatts that can and should be mined from that resource.

So, we have a unified --

MR. HEGERLE: Is there a sort of deadline or goal or anything at this point in place as to when that might take place? Is there a timeframe?

MR. FLUCKIGER: Yes, there is. In the Power Authority's investment plan, we have said that we think that there are two or three thousand megawatts that can be achieved over the next two to five years. We have also, in our reserves rulemaking, which isn't final, have talked about a goal of five to ten percent of peak load.

The PUC proceeding has not articulated such firm goals, but they are clearly looking at a number of tariffs that approach it in several ways.

So there are a lot of productive proceedings, and some dates that are beginning to come out of those.

MR. HEGERLE: Thank you.

MR. KELLY: We'll take the remaining card up from John Meyer, and then we'll turn after that to a question from David Mead.

MR. EVANS: I had wanted to comment on the earlier question.

MR. KELLY: Oh, two more comments then, John Meyer, then Peter Evans.

MR. MEYER: On demand programs, we certainly support heavily, demand programs, and, in fact, our company was very responsible for including much design in the Texas program of trying to get demand to bid into the market.

I think Kellan, though, has already pointed out that one of the major problems we continue to have is demand doesn't see the price signal, usually, and until it sees a price signal, it will not respond in the way that we think it might ought to respond.

In the absence of that, sometimes we show a wholesale price signal and then we let it bid capacity or the interruptibility right. And having said that, Reliant made a major attempt in the West, I think, back over two years ago -- I think it was for the summer of 2000, if I'm not mistaken -- to try to get megawatts bid into the market. And every state, almost, in the West, objected to it, of cutting or allowing customers to bid their load right, interruptibility rights, into a West-wide program. So, there is a lot of work to do there, I would say.

I guess the last comment I'd have about demand programs is, we had some in Texas like air conditioning direct control demand. And those programs cost three or four times as much as new generation, if you put all the loaded costs in them. You didn't usually see all the costs, because they were subsidized or borne by other ratepayers, but they are extremely expensive, if that's the type of program you go with, as opposed to allowing demand to respond on its own.

MR. KELLY: Thank you. Mr. Evans, you're up.

MR. EVANS: Just real quickly, one of the elegant features of classical utility restructuring was to separate generation from transmission and load serving, and, you know, with pricing between them, and that would at least hopefully move away from this bias towards using hardware to meet capacity needs.

And if we then patch that back together, there absolutely should be measures taken to try to minimize the effects of that natural bias. And I guess I would suggest that the separation idea is still a good one, and even if utilities continue to own their own generation, if there are -- between generation and transmission and load-serving, that is transparent, and other entities can participate in those markets, then it at least gives the opportunity for competitive alternatives to new capacity to participate.

I would encourage that structure, and not to abandon that structure.

MR. KELLY: Thank you. Now we go to David Meade with a question.

MR. MEAD: Okay, we've heard some disagreement about what the nature of the forward resource adequacy requirement should be and what and whether FERC should impose such a requirement. I'd like to ask a question about what happens if, in real-time, regardless of what the requirement is, what happens if, in real-time, there is a shortage?

What should the consequences be for that? The SMD NOPR proposed a couple of things: Should the ITP be directed, to the extent that it can, to curtail the people who have not brought resources to the market in real time?

To the extent that the ITP is unable to curtail those LOCs, should the LOCs who are taking energy that they haven't arranged for in advance, be subject to a very high penalty? Should that penalty revenue be used to compensate the people who were sufficient, but were curtailed anyway, or are there other ideas that you all have? Let me start with Mr. Stern.

MR. STERN: First, as far as penalties might go or consequences to the load-serving entity, based on what happens in real time, as I noted earlier, if such a penalty were to be imposed, first, I think it makes sense to have it take place at the planning stage, where the load-serving entity has a requirement and takes an action.

If you get to real time and there's a shortage, that can no longer really be attributed to the LSE in most case, because the LSE isn't the one that has the generation resources. They may have contract to add up to their plan, but they don't actually run the plants, and holding them responsible for those who do run the plants not supplying the power, really doesn't make sense.

And in this case, most of those contracts are already written, so you can't really say, let's put those terms in the contract. So, basically, if one wants to impose a situation in which those who did not plan adequately are sort of first on the list to be interrupted, while that makes a certain amount of sense, it may not turn out to be either technically or politically feasible to implement it, I mean, when you consider, for instance, the case of energy service providers, if they are the ones who fail to adequately plan.

Obviously it makes most sense just to make sure that everybody does have adequate plans, in which case then, if there is a shortage, it's due to events other than a party failing to adequately plan for the future, and the spreading of the outage under those circumstances would make the most sense.

MR. MEAD: So, briefly, you would say that in that instance, the pain for that shortage should be spread equally among everyone in that particular region.

MR. STERN: Ideally, everybody has sort of met their obligation on a planning perspective, to the satisfaction of the regulatory entity or entities that are overseeing it. And, therefore, if real-time occurs, and for some reason we see a shortage that the generation wasn't capable of providing and load was higher than expected, even if it was in one particular area, it wasn't because the entity in that area didn't fulfil its obligation to adequately plan; it was because of some other events, and that should be shared.

If, for some reason, we allow an entity to go forward without meeting its planning requirement, one could potentially design a system in which they were the first to be interrupted, if there was a shortfall. I think it makes more sense to simply ensure that everybody does satisfy that forward requirement, and then shortfall would be spread.

MR. KELLY: Mr. Reinhold?

MR. REINHOLD: I agree with what Gary said about the resource adequacy needs to be a forward-looking commitment, and once you get into real-time, it's really a different operational issue at that point.

But what WestConnect has done for real-time operations is, we do require balanced schedules from load-serving entities, and there is an adjustment process, if they fail to meet the resource needs.

First there is a screen as to whether or not there were other events which precipitated that, but if the LSE, just on its own, does not procure the resources and misses its load commitments, there's a system of escalating penalties, which escalates both in terms of the severity of the shortage that was experienced, as well as the frequency of times that those occurred over the past with that LSE.

I think it's problematical to try to program dropping a particular load for a single LSE. Certainly those systems may be technically feasible, but I think that's a lot more hardware in process than may be warranted at this point in time.

MR. KELLY: Mr. Meyer?

MR. MEYER: Yes, I just want to reemphasize, don't mix the planning and the resource adequacy requirement with the real-time operations. I was the head of dispatching at HL&P back in 1989 when we had one of the worst freezes in at least the history of Houston, and probably most of Texas.

And I would say that we actually had to shed firm load to protect against a full blackout. And it was actually because we lost -- we didn't lose it; Texas Utilities lost Houston and North Texas.

Now, at the time we were having to worry about shedding customers to keep from going fully black. I certainly wouldn't have had to have worried about who do I shed in this instance.

It was an emergency and we had to do it, and don't try to get into real-time operations penalties associated with a planning need. And as Gary very aptly put it, enforce those at the time the obligation has been presented to them.

MR. MEAD: Suppose a bunch of LSEs decide to sort of sell supply, the resource adequacy requirement they own or have under contract, their own generators, and it turns out that some one LSE's generation is far less reliable than the others?

Is there any mechanism that we ought to adopt to ensure that the plan, that each LSE's plan is met by reliable resources? And is there no role for, you know, sort of looking at what really happens in real time? Is it good enough just to have a good plan, or do we have to look at how it actually turns out in real time?

MR. MEYER: Various people have different ways to do it, but you could easily -- easily may be the wrong word, but you could track the resources and their response to availability, which would penalize them. Basically they couldn't supply anything above some historic availability.

But, again, at real-time, don't try to approach the need of what I'm restricted to do to protect from a system blackout. To me, that's a whole different issue and not something that you want to confuse.

MR. MEYER: Mr. Fluckiger.

MR. EVANS: I'd like to comment at the right time.

MR. FLUCKIGER: Right now, we have a system where blackouts are apportioned according to shortage. If one control area is short, it suffers a blackout and the neighbors don't, absent some precipitating event, transmission falling down or some contingency.

So that happens right now, and I agree with your premise that those that are short suffer the consequence. I also agree with what John said; you can't restrict the control area operator in a true emergency when the world is falling apart; you can't do that.

But to the extent that it's feasible and possible, someone that is short is suffers a consequence first. And clearly that means queued up first for blackouts, and you can't make that decision at real-time, so maybe you tag it after the hour-ahead process and you're done messing with it, so you've got the tag on the short people and they suffer first, if you get there.

There are a couple of other ways to approach this. If you force the system into an emergency, there are fines that are levied by the Reliability Council. If you're short, maybe those fines ought to be yours, too.

And if you can't technically interrupt the right people because you have load-serving entities that serve all the McDonald's in wherever -- and I understand how all that works -- then maybe there needs to be some kind of arrangement where those that are short are penalized in some way, and there's some kind of compensation for that. That's a possibility.

But, clearly, the principle, in my mind, is somebody that does not fill their need is certainly the one that bears the consequences.

But I also want to add to that what I said earlier. I think that the regulatory agencies over the utilities have the greatest incentive to penalize, make sure that doesn't happen, to do whatever, because they are the ones that take the heat on the front line and in the first place.

MR. KELLY: Mr. Connolly?

MR. CONNOLLY: I guess I'll echo Kellan's comments a little bit in that I think that we have to realize here that this probably is something that is going to be detailed enough that you want to leave it to the states or the regions to figure out.

Undoubtedly, these requirements are not just going to end up being about having sufficient capacity online. People are going to bring in environmental concerns; they're going to bring in geographic concerns, and those things may end up dictating where some resources are located.

And then if you end up having a problem in a load pocket because a transmission line goes down, well, do you punish the LSE because it met the requirements of the state advisory committee? It's probably something that you need to leave to the states and the regions to figure out how to apportion that stuff.

And the only other thing I'll add is that I would -- if you do have some -- if you do have some penalties that are assessed on a real-time market, I think you do have to make sure that those are targeted, because there are certain resources, intermittent resources, for example, that may find themselves in that market more often than others, and they would get a double penalty if you just put a peanut butter penalty in, in that they are already facing the volatility of that market, and if you slap a penalty on top of that, sort of uniformly, because they were operating in that hour or short in that hour, I think you double-hit them.

MR. KELLY: I want to reserve for myself, the final question, and, Mr. Connolly, you have led me right into it. If FERC does leave resource adequacy to the states and the regions, and for whatever reason, there is a region-wide shortage that results in high prices, should we deem those prices to be just and reasonable, therefore?

The flip side of the question is, if there should be bid caps in times of shortage, is FERC therefore compelled to have a compensating requirement for resource adequacy? And anybody who wants to answer it.

MR. FLUCKIGER: I'll go first. I'm sure everybody's got a thought probably. I said before each entity can decide how much to expose themselves in the spot market.

Let's pretend for a moment that everybody does do resource adequacy and they do it well. But on a hot day, we lose some resources, and so there's suddenly not enough and we end up in either a reserve deficiency or an actual curtailment or near there.

In my mind, those kinds of things do not justify essentially infinite prices. One of the questions really to answer about this is the question about rationing things only through price, and the appropriateness of that with this commodity. I would argue that it is not appropriate. I would argue that this commodity is too essential to do that with, at least in our current environment.

And until a number of developments take place, including appropriate demand response and condition that may exist in the future, pure price rationing is not appropriate.

So there are cases where someone who chooses to expose themselves to a spot market clearly exposes themselves to some degree of volatility. But price mitigation, price caps, let me just do a little example. Prices to go to really, really, really high. Someone does a really good job of planning, and the only thing they've got in the spot market is load forecast error.

So because somebody else's resource dripped, and prices go to a billion dollars, all of a sudden I lose my shirt as a supplier because of my forecast error, because somebody else did something. We can't put a structure in place that penalizes participants in that way, I don't think.

So I think there's still an appropriate place for price caps, and we can argue forever about the level and what they do and don't do to investment signals. But when you combine that with contracting, and I don't think generators are getting built on spec, I think that becomes less important.

MR. KELLY: Mr. Stern?

MR. STERN: I think I'm basically saying the same thing as Kellan here. But the mitigation measures that we're talking about are associated with mitigating exercises of market power, not mitigating the higher costs from having to use higher cost resources during scarcity situations or having insufficient resources, in which case in theory, the scarcity price is coming from the demand setting the bid.

That's not why we're putting mitigation in place. We're putting mitigation in place because it's not appropriate if things are tight for a seller to be able to say, well, you know what? I'll sell my product for 50 times the normal price today because I can get away with it. That's why we have mitigation in place. That's not scarcity. That's a market power abuse.

And we should be able to effectively differentiate those things and prices should be high during times of scarcity, but not unlimited, because we're allowing the exercise of market power.

MR. KELLY: Thank you. The last card up is John Meyer.

MR. MEYER: I'll take a slightly different view, though I guess general economic theory would indicate some similarities. But the idea of mitigation is, at least in my mind, is not to impose restriction during times of scarcity. And your definition of a shortage is a scarcity condition, no matter what causes it.

It could be caused by forced outages. It could be caused because people don't forecast correctly. It could be caused by droughts. It could be caused by hurricanes, whatever. It's a scarcity condition. And the price has to rise during scarcity, or we don't have a market. That's just the bare fact of life. And we're going the wrong way if we don't want that to happen.

So whether it should be unlimited or not, I'm not sure I want to go down that path. Obviously it should be, there's probably a natural cap of what the load response is. Do we have the right one? Well, we'd probably disagree a lot one way or the other whether we picked the right number so far at least to markets.

But we would all probably agree load would eventually cap it if it was allowed to respond and bid accordingly. So I think definitely it has to be allowed to rise the price of scarcity.

And I think this whole issue is about if you're going to have mitigation in the day ahead, real time markets, you're not going to allow fixed cost recovery of all generator, and you have two choices: Either that has to be built on, or you have to suffer the consequences. And I don't think we're ready for the consequences.

So I would propose that we build this into the SMD, much as it has already been done, except expanding the role to assure adequacy instead of the penalty structure that's in there.

MR. KELLY: Well, I want to thank this panel, not only for your enlightening words, but also for most of you flying 6,000 miles round trip to deliver them to us and starting a meeting at 6:30 in the morning in the real world.

So we appreciate your efforts. We'll conclude this panel now, and the next panel will begin on the hour at two o'clock Eastern Time. Thank you.

(Whereupon, at 1:15 p.m. on Tuesday, November 19, 2002, the FERC Technical Conference on Resource Adequacy recessed, to be reconvened at 2:00 p.m. Eastern Time the same day.)

AFTERNOON SESSION

(2:00 p.m.)

MR. KELLY: I'm sure many of you picked up a program from the back of the room and saw that the next panel up is scheduled to have Bill Hall, William Hall of Duke on the panel. Unfortunately, Mr. Hall, who was here in D.C. last night, got a call regarding a family emergency and had to fly back home. So we hope all is well with him. And he won't be joining us today.

We do, however, have six distinguished panelists to enlighten us on what the Commission ought to do in its resource adequacy requirement. Some, not all, of the panelists are sort of from the heartland of the country, not from the West or the Northeast, but the rest of the great USA.

And I see people are still coming in, but I'd like us to start on time relatively, so we'll begin with James Caldwell. Jim is Policy Director for the American Wind Energy Association. And, Jim, you've got three minutes.

MR. CALDWELL: Well, as you might imagine, as the Policy Director for the Wind Association, I'm going to answer the last question you asked first, which is how to calculate the capacity value or capacity credit for an intermittent resource like wind.

And the answer is actually one of those things that's fairly simple. It's the change in the effective load-carrying capability of the system before and after you add that resource.

Now having said that, how do you end up calculating that? Actually, when you go through the procedure and you go through the process and there's a fairly well developed academic literature, and there's a lot of use and a lot of experience with these kinds of calculations for load mainly. But there is a fair body of literature and results and experience around the world.

And what you end up with is basically that the capacity value ends up being the capacity factor of the resource. Adjusted in that capacity factor includes any forced outage rate that you have. And then it's adjusted for the conformance of the energy delivery to the load shape and also adjusted for the characteristics of the other generating resources in the region.

So those adjustments only matter when you start to get something on the order of three to five to six percent of wind resource in a particular region. They begin to get pretty interesting at about 10 to 15 percent intermittence, and they get really important when you get up to about 20 percent.

And so I would submit that we don't need to worry so much about the adjustments at this point. Hopefully, my children anyway will be worrying about the adjustments, but right now I don't think they much matter.

The second question I'd like to cover in my opening statement has to do with transmission. And that is, is establishing a deliverability standard for reliability in the interconnection process and in the use and the resource adequacy. And that deliverability -- something like what started off in the interconnection NOPR and as used today in like PJM in New York. And I'd point out that that's a much lower standard than, say, long-term ATC, which is used in the interconnection, long-term firm ATC, which is used in the interconnection process.

And that represents a huge barrier to entry for new resources of all kinds, wind included. And that has a real effect on the cost effectiveness of a resource adequacy program. We have to stop thinking about each resource in isolation. We have to stop thinking about firm and flat blocks and long-term firm ATC and balance schedules. We can't afford to vulcanize the grid by 138 control areas and then further vulcanize it by 6 or 7 or 10 schedules per control area.

If we do that, reliability will be too expensive. And the harder we try to do that, all we're going to end up with is higher prices and less reliability. What we've got to start doing is, is that we've got to start thinking about the system as a whole. We have to start using terms like "effective load-carrying capability", "deliverability". We have to get into issues like queue reform, the interconnection NOPR, and vigorous enforcement of that NOPR.

Thank you.

MR. KELLY: Thank you. For those who arrived a little late, Bill Hall from Duke will not be able to be with us today. Our next panelist is William Head, Chief Operating Officer of MAPPCOR, representing the Mid-Continent Area Power Pool.

MR. HEAD: First of all, thank you for allowing me to participate in this topic that's very important to us in the upper Midwest.

The Mid-Continent Area Power Pool has been a generation and reserve-sharing pool for 30 years. Our goal is to assure long-term resource adequacy and to reduce costs by sharing reserves.

Currently, the MAPP members are required to maintain a 15 percent reserve capacity obligation, so each member individually has to maintain that 15 percent at all times.

MAPP has an extensive set of definitions, rules, policies and procedures that define compliance with that reserve capacity obligation.

In addition, there are significant monetary consequences to a reserve capacity deficiency by a pool participant. In response to the proposed rule, MAPP has issued a paper titled, "Guiding Principles for Planning Reserves".

MAPP believes that in a competitive electric market structure, objections to a planning reserve mechanism would dissipate if all load-serving entities were required to meet an enforceable planning reserve requirement either individually or as part of a reserve-sharing arrangement.

It's unfair for load-serving entities in one area to be subject to reserve capacity obligation when their neighbors are not, which is the case today. We agree with the concept of beginning to level the playing field, so to speak, in this area.

I won't go through all the principles in the MAPP paper, but would like to address just a few issues where they may differ from what's in the proposed rule.

Percent reserve margin is not a measure of reliability or resource adequacy. We think a better standard is one of a loss of load probability from which a reserve margin can be determined. Reserve margins will vary from one region to another and one load-serving entity to another for a consistent level of reliability, such as a loss of load probability.

Penalties should be assessed on an after-the-fact basis. Forward-looking reserve margin penalties seem to be unworkable and unnecessarily complicated.

Load-serving entities should be able to acquire resources right up to the hour when they're about to go deficit. Trying to penalize someone before they've actually failed to comply doesn't seem reasonable.

There's a real need for consistent use of definitions, criteria, assumptions, policies and procedures if a reserve adequacy requirement is to be meaningful.

There's a need for flexibility in the rule so that successful reserve-sharing arrangements can continue to reduce the cost of generating capacity while maintaining electric system reliability.

MR. KELLY: thank you. The next speaker is Stephen L. Huntoon, Senior Director and Regulatory Counsel of Dynegy Power Marketing.

MR. HUNTOON: Thank you, Kevin and the Commission Staff for the opportunity to appear today. The focus of my remarks -- and I have some slides which I tried to distribute to folks -- is research that we've been sponsoring with some other generators at Johns Hopkins about trying to quantify the relationship among energy caps, resource adequacy and system reliability.

As you know, the concern is that it's been discussed already this morning in some detail, is that when you set price caps below a certain level, you won't have sufficient generation investment on a long-term basis to sustain the one day in ten year loss of load probability that is pretty much the accepted standard.

And there has been research that's been done on the relationship between price caps, installed capacity obligation and reliability. It appeared last year in the Electricity Journal, Hobbs, Inan & Stoft. And we have sponsored some new research by -- I'm sorry. It's Inan and Bowen -- that updates the prior work and evaluates the specific resource adequacy requirement that's in SMD. And Javier Inan is actually is actually here today. I don't know if he'll wave or not, but he's there.

Generally the research approach involves taking the input from PJM and using data that is available from PJM and assuming that everyone is acting in an economically rational basis. And we look at three things: An energy-only market that has price caps, an energy-plus-capacity market, and then the SMD's resource adequacy requirement, the proposal that was in SMD.

The first chart in the slides basically answers the question what does the energy cap need to be or what's the minimum you can set it at in order to ensure a one-day-in-ten-year loss of load probability in an energy-only market, and there are a couple of data sets that were run but the bottom line turned out to be that if you set it any less than 30,000 a megawatt hour, you're endangering the one-day-in-ten-year loss of load probability that you're shooting for.

The next chart I have addresses the scenario which is to say what's the tradeoff roughly between an energy-only market and an energy-and-capacity market if you want to reduce the energy price cap down to say, a thousand dollars. And the answer is, you need a certain stream of capacity revenue in order to meet the same one-day and ten-year loss of load probability. You need a very substantial capacity revenue and the way this model was approximately $70,000 a megawatt year.

The third thing that we looked at, we asked the Hopkins folks to look at, and it is the last chart in the slides, is an attempt to answer the question, what level of penalty do we need to have in an energy level in an energy-only-market under SMD's adequacy requirement, and the calculation that we ended up coming up with, or the Hopkins folks came up with is indicated that instead of the $500 or

$1,000 penalty that would be necessary to sustain reliability under the S&D proposal, you really need an energy deficiency penalty in the $20,000 a-megawatt-hour range to sustain reliability again at that one-day-and-ten-year.

So appreciate the opportunity to appear and be happy to answer any questions, thank you.

MR. KELLY: Thanks. You did a lot in three minutes.

Our next speaker is Sam Randazzo, a partner with McNees, Wallace & Nurick, LLC, on behalf of Ohio Industrial Consumers.

MR. RANDAZZO: Thank you. From our perspective, the opportunity to address questions like generation resource adequacy are necessarily dependent on getting the LMP congestion management engine up and running over as broad a part of each interconnect as possible. We continue, as a result, to urge FERC to make this the first priority. This will give us the information that we need in order to get a better assessment to what the system is actually capable of contrasted with the multi-control area configuration that dominates physical behavior in the Midwest.

Until then, we suggest that efforts to quantify a capacity reserve margin objective or implement untested business rules to ensure generation adequacy or, based on conversations I've heard today ensure fixed cost recovery for new entrants will not be productive.

Resource adequacy measures will be better undertaken once we have the system reliability information that is essential to run the LMP engine and I would note that ultimate customers today are paying for generation reserves in the bundled and unbundled rates that they're currently paying.

To the extent that there are issues regarding needing to provide compensation for new entrants, I suggest that maybe we ought to consider using the existing funds that are being paid and redirect them to a different purpose.

One of the things that I think is important to recognize here is that load is presently the providers of liability of last resort. If there's not enough system capacity, load is the one that makes up the difference, either to protect equipment or in some cases to deal with prices that are unacceptable to the load serving entity.
The reliability and demand response functionality provided by load is inherently in interstate commerce. And I believe a simple legal observation gives the Commission an opportunity to jump start the participation of load in the market.

That participation is presently dependent on proceeding through traditional channels that have not been very open to load's participation in the market. And sometimes it is useful to have an RTO, an independent RTO in that chain or that channel in order to reduce the resistance, but I suggest to you that the present discussions that the RTO world are often more focused on bulkanized negotiations over how individual transmission owners are going to join the RTO, what revenue guarantees they're going to get than they are about resource adequacy or loads' role in solving the puzzle.

We provide, in some written comments, some suggestions on how to get load more directly involved and also to make more visible what load is presently doing in terms of providing physical reliability as well as price response behavior. There are many load participation programs in unbundle choice and non-choice states. Unfortunately, they are not being coordinated relative to more systematic objectives.

One of the things I want to mention in the brief time that is left in the context of resource adequacy is the difficulty that business is increasingly challenged by their own competitive pressures or experiencing in this process. They are paying stranded costs, they are underwriting the networks' fixed costs, they are confronting uncertainty about the potential symmetry between receipt of CRRs or FTRs and being asked to pay the growing costs of getting RTOs up and running, and they are going to be asked to pay all the costs associated with getting new markets up and running as well.

The difficulty that this presents is that we've got to deal with all these costs that other stakeholders are asking and then support regulatory efforts in RTOs and in incumbent utilities participation, providing our last dollar in order to field a customer driven team to make sure the devil is not in the detail. And I suggest to you that the urgency associated with getting load more directly involved it the market so that load can make a business case that rationalizes participation in this long and enduring process may be one of the most important subtle points that I would like to communicate here today.

Thanks very much. I look forward to your questions.

MR. KELLY: Thank you. Rick Riley is the Director of Transmission Policy at Entergy Services, Inc. on behalf of SeTrans Sponsors.

MR. RILEY: Thank you for allowing me to speak on behalf of the SeTrans Sponsors today. The SeTrans Sponsors agree with the need to have a resource adequacy requirement in order to mitigate price spikes while ensuring sufficient resources are planned on a long-termed basis. An installed capacity requirement will provide a long-term signal that should assist in the development of new generation or the ability to dispatch load particularly in the early days of the RTO markets. While an installed capacity will provide an incentive for developers to build new generation, it will also promote the development of dispatchable load.

In order to accomplish this, resource adequacy responsibility should take the form of long-term obligations possibly on a multiple year basis. When more load is developed the capability to be dispatched, when resources are tight, less generating capability will be required to ensure reliability for the remaining load.

The SeTrans Sponsors are concerned, however, with the penalty structure proposed in the NOPR. The proposed penalty structure may not provide the proper incentives for load serving entities to secure adequate resources on a prospective basis. It is also not clear how the proposed penalty structure would handle LSEs who gain or lose load relative to the base forecast or the LSEs who buy or sell contracts in the interim period.

Additionally, the SeTrans Sponsors are concerned with the proposed process for determining the regional requirements. The Southeast is characterized by a business model in which bundled retail services are provided to customers via both state regulated, vertically integrated utilities as well as public power utilities. In fact, less than five percent of the load within SeTrans will be able to have retail choice of when the RTO has its day one operations. So the jurisdictional utilities in the Southeast, in accordance with state regulation, are currently utilizing long-term integrated resource planning processes that currently guarantee resource adequacy. Accordingly, the SeTrans Sponsors believe that the resource requirement should be determined by the SeTrans RTO in conjunction with the LSEs and the controlling regulatory authorities within the region.

The resource requirements should be developed using a system-wide statistical evaluation of system reliability using typical industry reliability measures, such as an LOLE requirement.

With regard to capacity markets, the NOPR permits but does not require RTO markets from requiring and trading resources for the purposes of meeting the reserve margins' supply requirement. The SeTrans Sponsors agree with this approach. We feel that allowing regional variation in allowing some markets to develop in certain regions, such as the Northeast, as opposed to the Southeast, where we feel like the bilateral approach is the appropriate method.

Consistent with the S&D proposal, however, there's nothing in our SeTrans Sponsors' proposal that would prevent the RTO from operating a market at a later date.

That will conclude my opening remarks. Thank you.

MR. KELLY: Thank you. Our last panelist is Raymond J. Wahle, Wahle, did I pronounce your name right?

MR. WAHLE: Wall (ph.)

MR. KELLY: Excuse me. Raymond J. Wahle, Director of Power Supply and Operations, the Missouri River Energy Services.

MR. WAHLE: Thank you for allowing me to speak here today. Missouri River Energy Services supports a well-defined resource adequacy requirement. We believe that each LSE needs to have enough capability to meet its load plus its resource adequacy obligation at the time of its peak. The necessary elements to have a resource adequacy requirement would first include: a minimum resource adequacy standard which all LSCs must meet; resource adequacy needs should be allocated to load serving entities based on each LSEs actually loads, not forecasted future loads. The reasons are that forecasts are always wrong and sometimes are hugely wrong.

Basing LSE's resources requirements on forecasts will induce under-forecasting loads and over forecasting resource additions. Actual load provide a very exact measure of what the loads of an LSE really are.

The second element would be elements that are to be used by an LSE needed to meet its adequacy resource standards must be accredited, must follow the accredited rules as established by the regional reliability organization. An LSE should be required to have an adequate amount of generating capability and demand side resources to meet its peak load plus its reserve obligations at the time of its peak. These obligations can only be met with accredited resources. This generating capability and demand side resources must be accounted for in a uniform manner which assures the use of consistently attainable values for planning and operating the system.

The rules for accreditation should be established by NERC and the regional RROs.

The third element is that all LSEs must report both before the fact and after the fact their loads and accrediting capability. In order to ensure that there are no double counted resources, the RTOs or ITPs would have to coordinate the reporting requirements.

The fourth element is penalties should be assessed at the time of the LSE's individual peak if that LSE fails to meet its resource adequacy requirements. The penalty, as proposed in the NOPR, is inadequate, and should apply to capacity shortages, not energy shortages. The goal of a long-term resource adequacy should be to have adequate electric generating and demand side resources.

To ensure that adequate capacity is built, the penalty should be applied to those LSEs who failed to build or contract for adequate capacity or demand side resources. The penalty needs to be greater than the cost of owning or implementing the demand side resources; otherwise, entities will find it more beneficial to pay the penalty than to build he resource.

The fifth element is the ITP needs audit rights to the LSEs data so that it can assure that the reliability criteria's being met and assessed penalties as necessary.

And a sixth and final element is there needs to be a deliverability requirement. However, I should note that this is a difficult issue to address because the deliverability requirement of the resource adequacy is inconsistent with the whole L&P system. However, whatever the deliverability requirement is, it should also extend to the demand side resources. Thank you.

MR. KELLY: Thank you. I've been trying to get Dave Mead's attention to see if he wants to start but I've failed, so while he's thinking about it, let me start.

Several of the panelists talked about the enforcement of a resource adequacy requirement, and I think one said the penalty was inadequate, although I don't think there is a penalty in the proposed NOPR, but there's a question about how high it should be. And Mr. Huntoon provided an answer of $21,000 megawatt hours, that's pretty high.

I'd like to explore with this panel to start, assuming here is a resource adequacy requirement and assuming that it's enforced, what should the enforcement mechanism be? Should it be a penalty, what should the penalty be applied in real time or at the time you failed to meet the requirement? Is an alternative to a penalty to lose service? Is there some third alternative other than those three?

Some people say well it ought to be simply a requirement that you have to pay, although as I mentioned this morning sometime that translates into a penalty, how should it be enforced. If you want to speak, anybody, just turn your card up, and I'll try to take you in turn. Mr. Head you go first.

MR. HEAD: Well, I can describe very briefly what seems to work very well in MAPP, and we've done this, like I said, for many years, basically it's an after-the-fact audit of all the members. The members can continue to acquire accredited resources right up to the hour that may go deficit of their 15 percent obligation. If a member is found, after the fact, to have gone deficit, they pay an allocation to the parties in the pool who had excess reserves above their 15 percent. The up to or capped rate on that is nominally about $90,000 per megawatt season, so they would pay that for the six-month season that they went deficit in.

For a couple of years, we lowered that to $45,000 per megawatt, and that didn't seem to be high enough to incent the appropriate behavior and we had a flurry of deficits for a couple of years, probably for that reason, but also probably because of some transmission constraints that we have in the region as well. Starting in the summer season in 2003 --

MR. KELLY: Could I ask you -- excuse me for interrupting but you talk about members of MAPP -- is the enforcement mechanism that members of MAPP join MAPP voluntarily, sign a contract and the contract, if they fail to live up to it, is enforceable in court, or is it something other than that?

MR. HEAD: The service schedule, Service Schedule B is a filed service schedule with the FERC, so there's an enforcement mechanism there. The MAPP agreement is a contract.

MR. KELLY: Would you come to FERC for the enforcement? Many contracts approved by FERC are actually enforced by courts, as opposed to by FERC itself.

MR. HEAD: I'm not a lawyer so I'm not sure I'm qualified to get into that.

MR. KELLY: Fair enough. Please continue. I interrupted.

MR. HEAD: That's fine. So starting the summer of 2003, we're actually going to start for very small deficits at about half of the cap rate and ramp up linearly to about 4% deficit to the cap, and then anything above that, you would pay the capped rate. In the operating reserve horizon, there is no penalty in real time operation.

But what you find is, if people are meeting their reserve capacity obligation shortages in the operating time frame typically are not a problem.

MR. KELLY: Thank you. I think Mr. Wahle had his card up second. How would you enforce it?

MR. WAHLE: I guess when I see that the penalty should be assessed, it should be assessed at the time of the LSEs peak. If they fail to meet the resource adequacy at that point, that really is the failure to meet reliable system standards, so I think it should be assessed at that point in time.

MR. KELLY: You say at the LSE's peak?

MR. WAHLE: Yes.

MR. KELLY: At the summer peaking system, but at a particular LSE peaks in March, and it fails to have enough resources under contract, even though there may be loads to buy from its surrounding neighbors at that time, it would receive a penalty.

MR. WAHLE: That is correct. I mean the whole idea behind it is is that you enforce this same obligation on all LSEs equally, and I should point out if that LSE fails to meet its peak in March, capacity at tha point in time is very economical and if they fail to go out and contract, I mean you can contract obviously for this capacity, if they fail to contract in March for that capacity, that is a real serious failure on the part of the LSE, so I wouldn't feel sorry for that individual at all if they failed to do that.

And then the other thing is the cost of penalty, just to address that. It has to be significant enough. What I suggest would probably be two times the cost of ownership, as your cheapest alternative, and if your cheapest alternative is a simple cycle turbine, in our region, that would cost you about $50,000 a year, so the penalty would be close to $100,000 a megawatt year as I think an appropriate penalty to provide the right incentive to install the capacity.

MR. KELLY: Would this penalty be -- what would be the source of the penalty? Would it be a FERC transmission tariff, an agreement among the parties, how would you see that working?

MR. WAHLE: Right now in the region I'm in, I'm also in the MAPP region under the MAPP tariff and it's under that FERC-filed tariff at MAPP, it could be a tariff or it could be a generation reserve sharing pool under another contract. I think either one would work well.

MR. KELLY: So for most MAPP members in the MAPP region right now, there is a resource adequacy requirement and FERC is involved in the enforcement, and it has been historically.

MR. WAHLE: I don't know if FERC has been involved in enforcement. I think that's just come through the assessment of the penalties, and I don't know if they've ever been challenged.

MR. KELLY: But in the sense that we, that FERC approves the penalties in the tariff so if there were to be an enforcement, there's a FERC role in establishing that? Good, thank you.

Mr. Huntoon, how would you enforce a resource adequacy requirement?

MR. HUNTOON: By my count, I think we've heard five questions, so I'm going to try to answer them all real quickly. First of all, I agree with people that spoke this morning that said that physical curtailment is simply not a conceivable option for enforcement going forward so we're looking at financial penalties of one form or another in any event.

Should the penalty be based on what kind of time period? Well, it should be based on the subject time period for whatever mechanism it is that you're using to ensure reliability. In the case of a bilateral installed capacity obligation, then you've got a deficiency rate that's due for the planning period in question, that's how it is applied. If you're talking about a centralized procurement model, then the LSE is going to have to pay the auction clearing price at the relevant period, the current period. If you're an energy-based deficiency mechanism, like the one that was laid out by someone in the NOPR, then it's really a dollars-per-megawatt-hour and that's where we calculated the kind of number you needed to ensure reliability under that mechanism.

As for what's the relevant time period, the reason why it ought to be the system's peak, not an LSE's own peak, is because in order to ensure system reliability, you're really interested in the system coincident peak, and that's why that's the relevant time to be ensuring reliability.

As for enforcement you need, among other things of course, clear and enforceable credit requirements to make sure that someone just isn't leaning on the system in a financial sense any more than they're leaning on the system in a physical sense.

And finally, I'd just like to underscore the points that have been made earlier about penalties. If you're getting to the point where you're actually enforcing a penalty, then it's probably too late, so you need to have penalties that are designed to adequately deter non-compliance so you never actually have to worry about collecting it.

MR. MEAD: Kevin, can I follow up on your question for a second? The answers, so far, at least as I have interpreted them, have been with respect to the penalties that the LSE would face for failure to meet its requirement. What obligations would you put on the resources and would you impose any penalties on the resources for failure to meet those requirements?

MR. HUNTOON: If I could just answer that real quick. If it's a capacity resource under any of the models that I'm familiar with, and it's receiving compensation, and it violates the rules under which it's available as a capacity resource, then it forfeits the revenue and again it has to forfeit enough revenue no matter what period I'm talking about so that you've adequately deterred any capacity resource from essentially reneging on the obligation.

MR. MEAD: Would you see any link between the penalty that would be imposed on the LSE for failure to meet the requirement in the first place versus the penalty that would be imposed on the resource for not living up to its obligation?

MR. HUNTOON: It's a good question. I actually haven't tried to compare the numbers under any existing system. I don't know. But there's no reason why they shouldn't be in line with one another.

MS. FERNANDEZ: I guess on sort of a follow-up, and I do want to bring Mr. Riley in, if you're doing it through a bilateral system, for example in MAPP, would the LSE have a contract with the generator? Assuming it was a third party, it wasn't your own generation. Would you have contractual remedies if the generator didn't show up?

MR. HUNTOON: Yes. And in fact, the parties submit those contracts to the staff at MAPPCOR, and they're reviewed for certain terms and conditions that are required to be accredited.

MS. FERNANDEZ: Okay. I was wondering in terms of -- Mr. Riley, I was going to bring you into this discussion -- because I was trying to figure out in the discussion as to how similar what MAPP is talking about doing, which seems like it's set up for an area that largely would have bilateral contracts. You don't have a lot of divestiture. You don't have a lot of retail access?

MR. RILEY: Virtually none, yes.

MS. FERNANDEZ: Largely vertically integrated utilities. Which seems like a fairly similar sort of industry structure to the SeTrans model. And I was wondering from the discussions how similar your proposals are?

MR. RILEY: That's a difficult question in that at SeTrans, we've developed a framework for a market model and have it put a lot of detail around how the capacity requirement will be implemented and also enforced.

It appears from my general look at the MAPP model that we're closely aligned to that. But again, we have a lot of stakeholder meetings to hold and to fully vet all the details.

I was going to mention that as far as a resource not meeting a capacity requirement, that would reduce the capacity from that resource that it could offer into the bilateral market. So we were looking at an LSE penalty for failing to meet their ICAP requirement. Then if a resource didn't perform, then there would be an impact on its ability to offer its full output into the market.

MR. MEAD: So as I understand it, the penalty for a resource failing to perform is not immediate. It's in how the ITP estimates how much capacity it has available to sell going forward?

MR. RILEY: That's correct.

MR. MEAD: And just briefly, why do you think that's the best enforcement mechanism for the supply resource?

MR. RILEY: At this time -- again, we haven't held a lot of discussions on the overall capacity requirement at SeTrans, and we focus more on the real time and day ahead markets. We agree with the need for capacity requirements, but as far as getting down to the details on the penalties, we haven't had a lot of discussions on that.

But we felt that the requirement should be placed upon the load-serving entities. They will have multiple resources, maybe many, and it would be up to that load-serving entity to get its portfolio of units or purchases to meet its requirement. And if one individual unit did not meet the requirement, we felt like the best way to penalize that unit would be to limit its ability to offer its full output into the bilateral market.

MR. GRAMLICH: Mr. Riley, could you comment on how it works today? Is it the same in the Southeast as it is for MAPP where the enforcement mechanism is in a FERC jurisdictional -- a FERC filed tariff?

MR. RILEY: No, I don't believe it is. I can't speak for all of the entities in the Southeast. I know certainly not in the Entergy tariff. We have requirements in each of our states and we operate in multiple states. There are agreements with our state commissions. And that requirement does not appear in our open access tariff.

MS. FERNANDEZ: Is the enforcement in the Southeast largely done through the state regulation?

MR. RILEY: That would be correct. Of course, at this time we're still fully regulating each of our states, although a portion of our service territory in Texas will see retail access or retail choice in the near future. The remaining states will remain regulated.

It's the same for the rest of the entities that are bundled utilities such as Southern and CLECO. So you'll have one load-serving entity per legal entity, and the enforcement would be an agreement between that entity and the regulatory authority.

MS. FERNANDEZ: In terms of the role of the state commissions, both serve as to how you're thinking of in terms of SeTrans and how it works in MAPP now, do the state commissions get involved in setting either the reliability requirement as to what level of reliability is needed and then MAPP figures out what type of planning reserves are needed to meet that requirement?

MR. HEAD: The states in the MAPP region for the most part rely on MAPP and their reserve capacity obligation as to resource adequacy mechanism. It is a very important thing to them. We visited all the commissions, either myself or one of my colleagues this year. And I can say that pretty much across the board, it's their number one concern.

MR. KELLY: Could I follow up on that? Because outside the MAPP region in the traditional vertically integrated state, the utilities have an obligation to serve as part of their franchise and it's enforced by the state.

Most states will require a utility to look ahead, to do a demand forecast and say five or ten years from now, here's the expected load. Here are our plans to meet it. This is all before the last ten years. That was the traditional way of doing it.

So it was very much a looking ahead. And in your opening statement, you said something to the effect that a forward looking requirement is unnecessary. Could you explain that?

MR. HEAD: Assessing a penalty on a look-ahead basis is what I think is unnecessary. In MAPP we do it on an after-the-fact audit. You actually have to go deficit in real time to be assessed a penalty. In the proposed rule, it talks about assessing a penalty in real time for not demonstrating that you've complied three years in the future. That's the part I think isn't really necessary and is probably unnecessarily complicated to administer in the operations world, for instance.

I think it would be administratively pretty burdensome to do that and probably unnecessary.

MR. KELLY: Okay. We're going to go to Mr. Wahle, Mr. Caldwell and then Mr. Randazzo.

MR. WAHLE: I guess I would just like to drop back a little bit to answer one of the questions Mr. Mead asked, and that was how would an LSE penalty be connected to a generator penalty? And one of the things that we see is that we think that the resource adequacy requirement should be placed on the LSE. And the requirement should be clear and concise and the penalties well known by all.

And then knowing that, the LSE can develop the needed contract language between it and the generation provider, resource provider, so that if they want to have the resource provider take a certain penalty, then that would be part of the contract negotiations.

Also, I think that as part of the overall resource adequacy program, there's another aspect to all resources, and that is that the resource itself has to meet accredited capability. And that accredited capability can take into account such things as the forced outage rate, the maintenance history of the plant, and you can even go to nonfirm resources, intermittent resources such as wind, run of the river hydro. And the accreditation rules themselves can dictate how much accredited capacity that particular type of resource would basically be able to deliver to the market. And that could even extend to the demand-side resources.

So all the resources could fall underneath its own definition, and that's how much accredited capability that resource could deliver to the marketplace.

MR. KELLY: In your view -- could you just summarize what the resource would be obligated to do? Is it to be available to provide energy? To what extent can it suffer an outage? To what extent can it sell to another market? Can you just talk about that if you can.

MR. WAHLE: Sure. First of all, obviously it's a capacity market. So if it sells its capacity once, that's it. It can't sell its capacity multiple times. So obviously that part of it.

And then in terms of the accreditation rules itself, basically you test the unit. You can have a test of the unit on how much can the unit produce. And if you don't want to decrease the accredited capability based on the normal maintenance and outage cycle of the plant, then based on the test, that would be the accredited capability. That's how much the unit could -- that capacity could sell, if you will, to the marketplace.

If you had a unit that showed poor performance, then your rules could account for that poor performance and it would reduce its accredited capability. And that's all it could sell to the marketplace. And it's basically through the accreditation criteria that you get at how much the unit can deliver to the marketplace. And I think that works well for intermittent resources also.

MR. KELLY: Are you suggesting that FERC should set up these accreditation criteria as part of its rule?

MR. WAHLE: No, no. I'm sorry. I was looking at the NERC along with the regional reliability organizations would establish the rules for the particular region.

In the region we're from, there's a lot of wind resources, and so to have an accreditation capability defined for wind is probably very important, because we do have wind resources. There's a lot being developed and there's a big potential. So that's very necessary.

We don't have a big demand for run-of-the-river hydro. So it's probably not a need for having that. So I guess we'd look to the region to develop those particular rules on the amount of accreditation.

MR. KELLY: That sounds like a perfect segue to Mr. Caldwell.

MR. CALDWELL: It's better than it was when I picked up my card I guess. I think the accreditation process is one that we're not afraid of, and I think we need to get on with it. And as a matter of fact tomorrow, we're just starting that process in PJM.

And I do think the NOPR did talk some about NASB and so forth and kind of waffled around about who should do that, and I really don't care, as long as we do it.

And there is a lot of, even though I think it's fair to say that some of the details be done at a regional level, if that's true, then I think we certainly ought to -- or FERC does have a role in facilitating the communication among the regions. Going through this exercise from scratch, from ground zero, in 138 control areas or nine NERC regions or 22 security coordinator, it doesn't seem to be a very useful piece of our time.

And there should be some coordination here and some learning that goes on. And I think something like the NASB or NERC or you guys sort of offline in a way could certainly facilitate that process.

I guess the reason why I raised my card, though, was having said that we're not afraid of the accreditation process, as a matter of fact, given some of the numbers that have been bandied around here as what kind of penalties that are necessary, boy, do I really want a piece of that. I mean, that is pretty rarefied air we're talking about here.

And I guess that I would suggest that although we're saying, well, we'd never want to collect these penalties, that to the extent we even talk about those or having them or having them be real, that means at least occasionally somebody's going to be collecting these penalties, otherwise they're not real. And if those are the prices, I suspect that that's pretty politically unsustainable to think about those kinds of things.

And if that's true, then, I think we all better stop talking about dispatchable generation as the only way to meet these, and we'd better start calling Sam and some of his guys, even though that's going to cut into my revenues that I might get by joining this accreditation process and getting a piece of that. That's not why we put wind on the system. And I think anybody that's talking about those penalties as something that's real, we've got a bad system. We've got to fix it.

MR. KELLY: This is a panel of perfect segues, because you just mentioned Sam and he's up next. But, Dave, do you want to?

MR. MEAD: Could I just follow up for a second? One of the criticisms that has been leveled against some of the existing capacity requirement systems like ICAP is that the measurement of availability is sort of general and there's no extra reward for being available on peak when you really need it.

A day of availability on peak is worth a day of availability when there's lots of spare capacity. Is there a way to address that problem? Can the availability standard -- is that good enough, or do we need special penalties for being out on peak? Is there an answer to that problem?

MR. HUNTOON: You probably could structure incentives more so that a capacity resource that was able to anticipate the time of the system peak better than another capacity resource and focus more of its resources on being available at that specific time. I'm sure that could be structured.

You do now have a system, though, that does reward availability overall. And if I could just briefly address that accreditation process and about doing it. Even though we use a different name, we are -- the Commission is engaged in of course in effect in the accreditation process now with the rules that govern capacity resources in the Northeast and de-listing and the availability rates, the forced outage rates. These are things that are all effectively overseen by the Commission, although they tend to be down at the RTO level.

MR. KELLY: Sam Randazzo?

MR. RANDAZZO: I guess I'm struck by the level of detail in the discussions and the questions that are presented and would try to emphasize again the point that I tried to make earlier, and that is that the quality and quantity of information that we presently have in order to evaluate what the system is presently capable of satisfying is dismally low.

And from our perspective, until we have a better understanding of what the integrated system is capable of doing, focusing on enforcement, focusing on specific reserve requirements, whether mentioned by simple reserve capacity or loss of load probability index, seems to me to be, you know, an exercise that's worth thinking about.

But for the most part, I think people in the Midwest at least are proceeding based upon the reality that you need to have a reserve available in order to meet contingencies: Unexpected load, unexpected outages. And for the most part, I think you'll find the practice is in the 15 to 20 percent area rule of thumb.

And from a prioritization of work standpoint, I think that if we could get a better handle on what the integrated system is capable of doing, I think we'd find most of our bottlenecks and our problems are at transmission or delivery levels. And if we solve those, it seems to me that some of these issues get much easier to address. Because in the abstract, you force people to think about what is my bill going to look like as a result of this reserve margin or this penalty? Whether it's $20,000 or something else, and we don't make very much progress in that context.

MR. KELLY: Sam, as Ohio goes to retail access and some of the neighboring states like Michigan do also, what is Ohio doing to say that the old 15 to 20 percent reserve requirement is still in effect? Does it turn to those who de facto have the large share of the load and say they have to continue meeting it, despite the fact that in theory their customers could be bid away over the next few years by competitors?

MR. RANDAZZO: Well, as states have turned to retail access, what happens is now the distribution company in unbundled form is the provider of last resort. And it ends up picking up residual responsibility for serving load, either as a result of people that don't make a choice or people that make a choice and then return to the provider of last resort service. And those are safety net things that are done.

The reality is that Ohio really never set a reserve margin requirement. It was something that was reviewed in the context of rate cases looking at management prudency, management performance. It was a statistic that was gathered. If the utility had too much, it was subject to an excess capacity adjustment. If it had too little, it was subject to questions about what management was thinking about during their free time. And so you had that general kind of atmosphere.

And to the extent more often I think what we focused on is a situation where capacity was in excess of a target reserve requirement and then rationalizing the economic consequence of that between stockholders and customers and more frequently falling on the customer side of the meter.

MR. KELLY: Mark?

MR. HEGERLE: I was thinking of something a little bit different but slightly -- when you have a percentage number, whether it's 15 percent or some other percentage, how should that be spread across, whether it's generation, it's local, or imports or demand-side response? SMD talks a lot about having all three of those play equally. How would spread those across the three? And that would be open to anybody, but, Sam, you can go ahead and start.

MR. RANDAZZO: Quite frankly, I think that I wouldn't bother trying to dictate what the percentage distribution between those various components would be. My view here is that what the Commission is trying to do is to open the network, create an open architecture structure so that choices can be made based upon service objectives and price objectives by people that are evaluating those choices based upon other measures of value, whether it's producing widgets or running a hospital or whatever.

And quite frankly, I think that as we move into this more centralized thinking about portfolios and other aspects of reserve requirements, I think it starts to sound very much like we're moving back into government regulation that has as its purpose not only to assure adequate capacity but to make sure that new entrants have the ability to recover their fixed costs after assuming the market risks of entering the market.

MR. HUNTOON: There is a very important aspect for the demand side in any capacity or adequacy regime, and there have been efforts as you all are well aware of efforts to integrate the demand side into the capacity models, at least in cases like PJM where you have active load management, ALM, which is essentially a controllability of load on a short notice basis that entitles the end user to essentially capacity credit, and recognition that they're essentially capacity resources and were treated effectively like that.

Where I think it's become more difficult is to recognize retail customer load that is not on interval meters to recognize what their contribution can be to as essentially a capacity resource, or at least to reduce the attribution of capacity cost to them for whatever they might be doing or their supplier may be doing to shape their load curve. And we have run into problems.

And I think that's a challenge for the future that we probably still haven't come to grips with is how to make sure that under any capacity or adequacy regime that you have adequately compensated monthly meter customer for engaging in activities that is beneficial.

MR. KELLY: Jim Caldwell?

MR. CALDWELL: I think to answer Mark's question, I would say that the spread ought to be again related to a deliverability standard in the transmission side that is used for interconnection and for planning, and then let, as Sam would say, the congestion management system decide in real time who actually gets to use that capacity, and that that's going to be the cheapest way and the best way to figure out the spread.

And if you try to do that ahead of time at the planning regime, you're going to end up, as I say, restricting entry. You're going to end up with a much less slate of resources to deal with.

The other thing I guess I'd pick up on something David said. And I think we make a mistake when we think about capacity being valuable only on the peak day. I didn't hear all the panelists this morning, but the part that I did hear, nobody mentioned having a problem on what would normally be a peak day. They all mentioned on problems where they were unexpected, whether that was an ice storm or something else.

And you talk to the folks, and the problems, the biggest problems comes when there's a surprise. In peak days, there is rarely a surprise. There's usually these all hands on deck kind of things and everybody all lines up and the loads all knows, and everybody is aware. The problems in California didn't necessarily occur on the peak day, they occurred in the surprises. And the capacity has value throughout the year and throughout the hours. And that's why you had to deal with it on a statistical and probability basis, not on some deterministic just worrying about it on the peak day.

The last thing that I'd say is that second again something that Sam said, and that is that it's the tariff that matters. About two or three years ago at one of these things, I heard somebody reference some work that was done by Cambridge about what happened to spot prices and volatility and whether there was a liquid market and whether things hung together versus reserve margins.

And as I recall the exercise that was done, they talked about PJM being able to hang together real well in a 5 to 7 percent operating reserve margin in terms of having stable prices, liquid markets and not anywhere near any kind of bid caps or things like that.

I also hear California ISO talking about having to have a 20 percent bid coverage ratio or 20 percent kind of reserve margins in real time. And the difference in price or the difference in cost between those two standards is huge. On a system the size of PJM today, that's about $6 or $7 billion a year difference.

You know, the tariff that we're talking about here and the way we define these things, there's huge numbers involved, and we've really got to get it right. And we've got to let load play. We've really got to let load play, and we've really got to get these accreditation rules right.

MR. HEGERLE: So is it the accreditation rules that will allow load to play, or is there something else that we should be doing to make sure that they can?

MR. CALDWELL: I think the accreditation rules for load are probably necessary and not sufficient. I think that in some sense it's probably cultural, in that even in this room at this table, we talk a little bit about load or we talk a little bit about nontraditional resources and dealing with wind fairly, and then about two questions later, we're all talking about dispatchable generation and peak days and we're talking about, you know, things that we know and are comfortable with.

And we're just not comfortable with these things. And I think there's going to have to be some, I'll use the word affirmative action, to make sure that these things happen and that people actually get used to them, and that they begin to understand and deal with them, and that that's going to have to happen. It's going to have to come from here with some leadership.

And then once that happens and it gets in the culture, it gets ingrained in the system, then I think it'll be pretty easy to figure out.

MR. HEGERLE: What is that affirmative action? Is it a call for a percentage number that's demand response?

MR. CALDWELL: No. I don't think there's any -- I'm not talking about quotas. I'll use another word, because I was going to use affirmative action. I don't want to -- you know. I don't think it needs to be that. I think it mainly has to be some facilitation of process that happens.

I think what you're doing with demand response in New England is the right thing to do. What do you call it? Your demand response initiative or whatever. I think that's the right kind of thing to do. I think helping us get the accreditation rules for intermittent resources. I mean, just telling people that this is what you're going to have to do and give them some sort of timetable and reports back and using the bully pulpit is probably as important as anything.

Because I think that, again, given the size of the number and what we're talking about, there's way too much at stake, and once people get the idea that this stuff really does work and they get comfortable with it, it's going to go in like greased lightning, because these numbers are unsustainable. We can't think about penalties in the neighborhood of $180,000 a megawatt year or pit gaps at $90,000. I mean, it's laughable. It just isn't going to fly.

MR. KELLY: Sam, we'll hear from you, and then we wanted to go to a different line of questioning.

MR. RANDAZZO: I mentioned this earlier, and the question brings it to my mind at least again. I hope it does to yours. And that is that we have a lot of that is already participating in the market in both choice and non-choice states.

And I'll take a non-choice state. A while ago, PSI, which is a Cinergy operating company, started a problem that would allow interruptible customers who historically were simply interrupted when there wasn't enough to go around, to access the market through what we call a buy-through program. And that has a FERC jurisdictional or

Commission jurisdictional element to it because of the sale of wholesale.

But that load is currently participating in the market. We have similar programs in Ohio that we started several years ago, mostly as a strategy to try and give customers the opportunity to develop the skill sets that Jim was just referring to explicitly. Hundreds of megawatts of load.

We have other customers that would agree to be interrupted under certain circumstances and conditions but have not been permitted to play in the market simply because the incumbent utility did not need any more interruptible customers.

The experience that we've seen over the last three or four years is that notwithstanding the fact that we've had a growth in generating capacity in the Midwest, the duration and frequency of interruptions of these customers has increased. And notwithstanding the growth in generating capacity in the Midwest, the duration and frequency of power quality problems for firm customers has increased.

Now these customers on the end of a stick. They're being affected. They have no opportunity to exhibit a response. They're ready to do something. They're highly motivated because their plants are shutting down or they can't meet their production schedules. And all they're looking for is an opportunity to send a coordinated message back to somebody and a vehicle that is not presently as dependent on the current channels of responding as load is.

We keep sort of retreating back to the conventional structure, which is we're underneath a load-serving entity. The load-serving entity gets FTRs. They may follow the load eventually. They don't now. And until those nut-and-bolt issues are resolved, we're going to be constrained in terms of extracting the value out of people that are willing to exhibit an appropriate response to deal with price volatility and also to deal with reliability concerns.

Load is presently playing. I think it's up to you all to figure out how to get more value out of that playing opportunity.

MR. GRAMLICH: This is also for you, Sam. You described a region that is generally doing okay on capacity right now. I won't say flush, but doing pretty well. There's no formal mechanism right now for resource adequacy. There hasn't been in the past. It's generally a state responsibility. There is some movement towards retail access. The transparent markets coming in will help a lot and provide price signals and hopefully reveal a lot about what's happening in the market. But there's still no real mechanism with teeth.

And I wonder -- all of our jobs here are to make sure we never go through another California, and those features I just described could be -- have some similarity to California around 1997 or so. And so what you've described just now is that there's a lot of demand side ready and willing to respond. That would be a way out of the box. And I just want to get your level of confidence that we have enough of a mechanism with teeth here, whether, you know, whoever enforces it, is there something strong enough to make sure that this system is going to work?

MR. RANDAZZO: having lived through the natural gas shortage and dealt with the problems that came out of that area, I would say that you can never be sure that there's enough, nor can you count on enforcement mechanisms to discipline bad actors. You need to sort of take a look at the risks, manage the risks based upon a worst case scenario and hope for the best to some extent.

But I think at least in the Midwest, there's some room for taking some confidence in what I'll call Midwest common sense. You haven't seen the state-to-state turf battles. You've seen state commissions pretty much pulling together to try and take a regional perspective on these issues, thankfully out of the recognition that they are regional and were dynamically interrelated.

So I think, you know, if you see a state that is grossly underbuilt and is inclined to rely on external resources and yet is -- and there's not good cooperation within the region -- I think some red flags ought to go up.

That is not the case in the Midwest. But by the same token, I think there are some things that are going on below radar in terms of what is happening at the customer's meter that cause concern. The increase in duration and interruptions as well as the problems with power quality to me indicate that we've got adequate resources by all objective measures, and yet for some reason, load or demand is not being satisfied in a reliable fashion.

MR. KELLY: I'd like to ask this panel a question I asked earlier panels. What should the FERC do in the final rule? Just to give you time to think, I'll talk a little to fill the air.

But this is a group that generally supports resource adequacy. You all feel strongly about it. Mr. Head said it's very important that people who plan adequate resources not have their neighbors lean on them.

Generally you're in regions that historically have made provisions for resource adequacy. Maybe you wouldn't need a FERC rule at all. Would things change, though, as you get into Midwest ISO and into SeTrans as nodal markets are being set up, prices could potentially be more variable because there's more market-oriented environment, to where neighbors could lean more on neighbors if they don't plan individually?

And do you need a FERC requirement to help with the interstate commerce aspects of enforcing it? And if so -- so I guess it's a two-part question. One is should your RTOs do something? And what if anything should FERC say in the final rule? Should it be specific, general principles or whatever else you'd care to comment on? And the first card up is from Stephen Huntoon.

MR. HUNTOON: I didn't look to make sure I wasn't the first card up. Well, the final rule should lay out the framework for an appropriate resource adequacy requirement. How detailed I think can be debated.

But part of I think what the answer is, is in response I guess Dan Larcamp this morning asked the question about do people feel there's a relationship between energy caps, say, and capacity or resource adequacy. I think the answer, our answer is yes. So in the Midwest where there is no energy price cap, basically load has to make sure that it's not going to be caught short, and it has to essentially engage in self-help and bilateral contracting activities that make it unnecessary, at least under that set of circumstances, to have a specific resource adequacy requirement.

As you move to what was called I guess an organized market, organized central market, and then more load and more supply is now clearing under that organized central market, and then once you impose a cap on that market and you possibly add other forms of energy price controls on that market, now you've gotten -- now you're replicating the Northeast in terms of the way in which the energy market is working, and the counterpart to that is you now have to have a central prescribed resource adequacy requirement that works. And right now there's a form of it obviously in the Northeast and maybe it ought to be changed in some ways. There are people working on that, as the Commission is aware, in the JCAG context and other context to try to deal with some of its problems.

But I think that's the natural evolution of things in our view.

MR. KELLY: Jim Caldwell, I think you had the second card up.

MR. CALDWELL: I'll say it one more time that I think as long as you're talking about the numbers that you're talking about today, you've got to recognize that you're shuffling the deck chairs and that you're going to have to do something to lower the barriers to entry to new resources and to nontraditional resources.

And that's going to take some time, and that's going to take some time to get people comfortable with the new culture, and you're going to have to hope against hope that in the meanwhile things don't fall apart. But I think that says you've got to get a sense of urgency under the long-term, under getting the interconnection NOPR in place, lowering those barriers to entry, getting the small generator interconnection NOPR in place and vigorously enforcing those, and to take some responsibility and ownership for the things that are not on the system yet for the nontraditional.

You're going to have to get at least of the parts of the SMD pro forma tariff that relate to congestion management and allocation of the grid capacity in real time in place over as broad an area as you can as soon as you can. Because as long as you['re dealing with this vulcanized world you've got today, you're really at risk. You're really in danger. And you're going to risk high prices and unreliability. And the sooner you can get out of that box with the reforms that you know what has to go, the better off you're going to be.

MR. KELLY: Okay. We'll go to Mr. Wahle, Riley and Randazzo in that order. And again the question is, what should FERC do in the final rule with regard to resource adequacy?

MR. WAHLE: Let me write the rules.

MR. KELLY: This is your chance to write them. What would you put down?

MR. WAHLE: Assuming that that's completely not going to happen, I guess I think there needs to be some general principles obviously laid out in the final rules. And we do support resource adequacy. We'd like to see resource adequacy requirement in the rules.

In giving that adequacy requirement, then we would assign the responsibility to meet that requirement to the LSEs. I think that needs to be where it should be assigned, because it's the LSEs. They might have some unique opportunities with the loads in their area or with certain resources in that particular area that they can take advantage of the rules and implement a cost effective resource adequacy program. So it really should be assigned to the LSEs.

And then the other thing is, all generation needs to be able to play in that marketplace. We do believe that generation, demand-side resources and intermittent resources should be able to provide the resource adequacy to the market based on the accreditation. There needs to be an accreditation criteria for the various resources. So I think that's a part of the process.

And then of course the actual resource adequacy amounts I think should be set in a public process through the ROs and the NERC and probably even in the state with state input into that whole process.

MR. KELLY: Thank you. Mr. Riley?

MR. RILEY: I think I'm going to answer that question by restating one of your questions earlier. I think if you have bid caps then you are compelled to have the resource adequacy requirement.

You can have an energy market with unmitigated prices that will allow the scarcity to pay those generators enough to enter into the market, or you can have bid caps, and therefore you would need a requirement on adequacy to ensure that you have sufficient generation installed in the future.

So I agree that you need resource adequacy provisions in the NOPR or the final rule. But I think you need regional flexibility on whether you have a market or not, whether you have an organized market or not.

Certainly in retail choice states, the proposal that we heard from JCAG this morning on a central procurement may very well be the right way to go for markets that are predominately retail choice. But we don't think that's the right fit right now in the Southeast.

I believe it was Calvin Coolidge that once said you can't do everything at once but you can do something at once. And the SeTrans are something at once. We want that to be the day ahead market and the real time energy market. We think later on we may see a need to implement something like the JCAG proposal, but not all up front.

MR. KELLY: Thank you.

MR. RANDAZZO: My view would be that it's very helpful that the Commission continues to keep the need for adequate resources in front of everybody. I think it would be good in the final rule for the Commission to continue to do that. I think it would be useful if the Commission inquires of each RTO how they are going about the process of ensuring adequate resources.

Inventory what people are doing out there. Sometimes diversity of opinions ends up providing good ideas. And continue to examine the information that comes in from the implementation of the real time energy market and the day ahead market to be able to identify where we can get the most bang for the buck in making sure that the resources, demand and supply, get dispatched in a way so that we're delivering what people want at reasonable prices.

So I would say that the subject should not be closed. I would say it's too early to come up with a specific reserve requirement measured in any fashion because of the quantity and quality of information problems that I mentioned earlier. But I do think it's important for the Commission to reserve this as an important place where we need more work.

MR. KELLY: Thank you. Mr. Head?

MR. HEAD: I think it's appropriate that an adequacy requirement be in the rule. I also think it's important for the FERC to act in lockstep with NERC and the regional reliability organizations and the states on this if we're going to truly level the playing field across the interconnections.

Should the ITPs be the ones to administer the details of a program? Not necessarily. I think that they need to have a set of rules and criteria, but could certainly defer to reserve-sharing pools to handle the details.

As far as reserve-sharing pools, the bigger the better. that's where the money is really saved in this area in the sharing of capacity reserves.

MR. KELLY: A follow-up on that, though. Perhaps what we're asking in the rule is whether reserve-sharing pools should be mandatory so it's not voluntary whether you join or not. Do you have a view on that?

MR. HEAD: Should pools be mandatory? Not necessarily. I think that if the right reliability criteria are out there and let reserve-sharing pools form up to most efficiently meet that standard, that could very well work just fine.

MR. KELLY: Thank you. David?

MR. MEAD: I have a question for Mr. Randazzo. We heard a view this morning that resource adequacy requirements that must be met far in advance might discourage -- demand-side resources may be less able to provide those resources if the requirement is very far in advance compared to whether it's closer to the delivery day or the delivery year.

Do you share that view or concern?

MR. RANDAZZO: As in most things, my view would be that the answer depends upon the type of demand-side resource that you're talking about. Rural co-ops in our part of the country have had for years radio-controlled water heaters that are presently dispatched for purposes of improving purchase power load factor and avoiding very significant ratchets.

Part of the contractual relationships that exist in those organizations inhibit the opportunity for that demand response to exhibit itself in the market, because demand response is being operated largely for insular purposes that are confined to islands in the larger stream. So there's no reason why a capacity of that sort couldn't have a longer-term potential associated with it.

If you're talking about a voluntary arrangement with large industrials, there are various types of process, manufacturing process. I think of air reduction operations that have the ability to get off the system with almost no notice and relieve substantial amounts of load. They tend to be available for long periods of time, but again, those things are going to be subject to the specific needs and locations and to some extent, the cycle of the economy, as various forms of manufacturing change over time.

So I think it depends on the demand response. I think some can, some would like to be, some are presently providing that now involuntarily. And as I said earlier, I think our challenge is to get those demand responses coordinated to a higher purpose.

MR. KELLY: A question just for Mr. Head. I think it was you who mentioned that reserve-sharing pools should be as large as possible. And yet in the Midwest, there are lot of transmission constraints, TLRs, which will constrain how big they can be. How do you assess either the effect of transmission constraints on how big the pool can be or what ought to be done in terms of eliminating transmission constraints to meet resource adequacy?

I'd like just Mr. Head to answer that one unless people feel they have to comment, and then go to another line of questioning that we have in mind.

MR. HEAD: Transmission constraints definitely restrict what you can necessarily do within a pool. Nobody would argue that. Administratively, there may be savings in that the bigger the pool, you can save on staffing and things like that.

Where transmission constraints are today may dictate pockets in a reserve-sharing pool that perform together. Those constraints may not be there next year or the next year after that. Those will always move around as transmission gets built and more generation gets built.

MR. KELLY: Okay. Jim, do you feel you have to comment on that?

MR. CALDWELL: I do. I just want to tell a little anecdote. I think it was ten days or so ago I was up in PJM at the Reliability Committee meeting, and the Reliability Committee was getting a report on the integration of PJM West and PJM South. And the conversation sort of went like, well -- and it was in the same meeting where the members were getting their ICAP allocations for next year. And the ICAP allocations that were being passed out were 17.5 percent for PJM.

And then when they started talking about, you know, PJM West and PJM South, the comment was made, well, you guys better be on notice that the way we see it here, once we get that in from our deliverability calculations, that that 17.5 percent is going to go down to 15 and that capacity from Chicago is going to be deliverable to

Philadelphia under a tariff that is along the lines that Sam described.

And I think when we talk about transmission constraints and available transmission capacity, that's to the definitions and in the form that we take it now, and that's not the form that we can afford to deal with for the future, and that we're going to have to get to this idea of deliverability in terms of letting people get on. And then once that's available, then allocating the capacity between them on some other basis other than, you know, who had it 50 years ago or who signed up in the queue on Friday instead of Monday.

MR. KELLY: Thank you. Alice?

MS. FERNANDEZ: I was wondering from people, I think especially for the people in MAPP, it sounds like in your region you had reliability requirements with enforceable penalties that seemed to work for the region.

As we're getting into a system where we're getting into larger RTOs and where some of your members could be part of MISO, how does that affect what MAPP does? Does there need to be the same type of requirement throughout all of the Midwest ISO, or is it something where you can have a separate requirement for MAPP and differing reliability requirements in other parts of that same organization?

MR. HEAD: Yes. I believe that that's workable. That's exactly the way it is today. So it is being done today.

The MISO under contract to MAPPCOR administers the operating reserve program for all the MAPP members. They administer the operating reserve program for the other regions they're in, at a different location. So that is functioning today. They took that over and we never skipped a beat.

MR. RILEY: I just wanted to mention at SeTrans, we felt it very important to have one default adequacy requirement across the entire RTO. If you have Southern with one requirement, their control area, and Entergy with another, I think that free rider or leaning on the other, your neighbors, problem still will arise.

So we felt it important to have that one requirement. Now to the extent that your state regulatory requirement or your contractual requirement for some nonjurisdictionals has a lower number than the RTO number, then you would have to go out and procure more installed capacity. Or if you're a control area and you can curtail load, then you can do that as well.

But, again, we felt across the entire SeTrans RTO, we needed one requirement.

MS. FERNANDEZ: But I mean that would be a minimum requirement?

MR. RILEY: This would be a minimum.

MS. FERNANDEZ: So that it could have higher ones?

MR. RILEY: You could have higher, but it would be a minimum default requirement.

MR. KELLY: Mr. Wahle, do you have a comment?

MR. WAHLE: I was basically going to repeat what Mr. Riley just said. So, I agree with him.

MR. KELLY: All right. Mr. Riley, as you were talking, I couldn't help thinking about you seem to be almost describing what the Commission had proposed in its NOPR. I don't know if you realize that or not. In case there's a significant difference, maybe you could articulate for us now what it is.

MR. RILEY: I don't know that there's a significant difference. I think the penalty -- there were some penalties in the NOPR, but there was a structure whereby you would penalize entities if they actually purchased something out of the real-time energy market. And if they did that, then it would be -- I think there was a suggestion that it could be $1,000, the general question, or what should it be?

So we were concerned at SeTrans in reading that that if everyone else agreed it was $1,000 besides us -- we didn't think $1,000 would be enough. And seeing the information that Dynegy has put together, our suspicions may very well be true.

MR. KELLY: Do you know yet what you would substitute for that? Or would you just simply have a high penalty and say that's what it is?

MR. RILEY: We've characterized it as a severe financial penalty. Obviously that doesn't tell you a whole lot. In fact, at stakeholder meetings they say, well, what is a severe financial penalty? And we say we'll know it when we see it I guess. Do you have a suggestion? And the stakeholders told us that they would come back with a suggestion, and we haven't had an opportunity to have additional meetings and drill down to the level to see what that penalty would be.

MR. KELLY: You said, I think, Mr. Riley, penalties always come down to financial in the end. Somebody said that on the panel.

MR. RILEY: I don't believe that was me.

MR. KELLY: I think somebody said that. Stephen Huntoon said it. And you also calculated penalties needs to be $21,000 under a certain set of circumstances, dollars per megawatt hour, which Jim said is politically or practically infeasible.

I'm a little lost as to what to do with all those sets of information. If the only real thing you can do to enforce the requirement is ultimately a penalty, if the penalty is a certain dollar figure, let's just say it's $21,000 for purposes of example, if that's what it is, is that what you apply? Or is there an alternative?

MR. HUNTOON: At least my take on a penalty that is that high that's what's necessary to ensure that no one is tempted to free ride, is that you probably need an alternative approach like a JCAG or a capacity form of resource adequacy.

And that is what we are suggesting you probably end up with needing if you want to meet the one day in ten year loss of load probability and you want to have energy caps, which seem to be a given under SMD, and you also perhaps want to have other forms of energy price limitations that may limit the ability of generator to receive scarcity rents in energy prices.

MR. KELLY: But now the JCAG is just another form of saying it's alleged you don't have an alternative but to pay for your share of the region's capacity, and that if you pay your share, it'll be a lot more than paying one time the $21,000 per megawatt hour.

But there's always the question if somebody says I don't want to participate, I don't want to pay, when you ask folks in the Northeast, they say, well, then there'd be a severe financial penalty, and if you ask what that is, maybe that comes out to the $21,000 per megawatt hour. Is there any ultimate way to avoid -- I'm really trying to get at the enforcement mechanism. And it always seems to come around to every enforcement mechanism isn't feasible, so try something else, which ultimately comes around to being a penalty which is infeasible.

I don't know how to get out of that do loop, so I'm looking for some help on that.

MR. HUNTOON: If I can, it depends, to some extent I think, Kevin, it depends on what kind of structure you're instituting for resource adequacy. If it is a bilateral capacity construct, such as something like what exists now in the Northeast, then the way you impose -- you ensure that load is meeting its allocable share of the resource adequacy obligation is that any entity that doesn't incurs the deficiency rate. And the deficiency rate is designed to ensure that load meets its allocable share.

If instead you're gong to have a centralized procurement approach, which is not that dramatically different in many ways, then the way in which you're making it work in a sense is not really with a penalty structure. You're just simply assigning the cost that falls -- the price that price that's falling out of your auction mechanism or whatever it is you're using for the central procurement from the standpoint of the RTO being the buyer. You're simply billing that out to load on, again, whatever allocable basis there is.

I hope I'm answering the question.

MR. KELLY: But, Mr. Huntoon, is the study that you referred to in your comments by I guess Inan and Bowlard, is that in the public record anywhere?

MR. HUNTOON: No. These are the preliminary results and we're planning to file with that with the Commission in January with our comments on the resource adequacy question.

However, we would also suggest that, or at least throw out the possibility that the Commission either through the folks at Hopkins or through their own resources, do a simulation or model.

In other words, take the tentative final form of SMD with the way in which the energy market rules are going to be set up, whatever the resource adequacy mechanism is that you all settle upon, and make an assessment about what level of reliability you want, whether you want to apply the one in ten rule or lost load probability from NERC or something else, and then model it yourself and see if it all hangs together.

Because it may be that, and I think what this work is intended to indicate is that when you put things all together, it may be that you're sacrificing something.

MR. KELLY: When we do that, the prices come out high. It seems to come down to either people voluntarily join a pool, which they have in the Northeast, they have in the MAPP area, and it works fairly smoothly as it has historically, or if there is to be a requirement and people are not joining voluntarily, it seems to come down to the fact that there has to be a penalty, and the penalty has to be high enough to be what some people deem to be politically infeasible.

That's what I was trying to get at. I wasn't questioning the size of your penalty. Somebody else might get 15 instead of 21, but.

MR. HUNTOON: The impact on of course ultimate rates is really a function, not only the size of the penalty, but the frequency with which that penalty or cost is actually paid. And a penalty that might be paid one hour out of a year, for example, is going to have a very small impact on the overall cost.

MR. KELLY: Okay. I see some cards up and people want to ask some questions here. We do have a very large last panel, so I'd ask everyone to keep the final questions and remarks as brief as possible. Rob?

MR. GRAMLICH: Just a quick comment on that bit of research and the actual quantification of where the penalty or energy price cap or -- I guess those are the same thing -- where that should be. I'd encourage everybody to file that information, if you could file your workpapers to what you produced, and if others could comment on that. Sam might have a different view and others might have a different view on where the number is, but we will be looking very carefully at those numbers. So I'd just encourage people to file that in their comments.

MR. KELLY: The last word is from Mr. Wahle and Mr. Riley.

MR. WAHLE: thank you. I guess just a comment on the penalty. The penalty as we would envision it would be applied to capacity, not energy. So it would be $1 per megawatt, not megawatt hour. And so therefore, the high penalty that you would see really would represent a penalty to encourage generation ownership.

What we want to encourage is installation of capacity. And so you would tie it to capacity. I think that's how the penalty should be applied or effected.

And then the other comment is, how do you get there? Possibly through a tariff itself in the ITP that would have the requirement or the requirement entities must join a generation resource-sharing pool, which implies a contract, which could have in the contract the penalty provisions. And then of course the tariff, the penalty itself and the tariff could be filed at FERC.

MR. KELLY: Thank you.

MR. RILEY: Well, Ray stole my thunder. But I would suggest too that it would be some type of capacity payment. And if it's something that equates to the $21,000 per megawatt hour, that may not be politically untenable if someone did something wrong as opposed to having spot market prices that are very high.

So severe financial penalties may very well be these types of numbers. And I think you would have to have something like that to encourage the appropriate behavior. And even though I'm not an expert at the JCAG proposal, nor did I sleep at the Holiday Inn Express last night, it sounds like what they're proposing is more of a tax. And to the extent you can get out of any other tax, I don't know how you would get out of that tax as well.

So I think that's the framework that they have set forth. And to me, if you try to quit paying that particular tax, you quit taking service, you quit scheduling power, and you have other problems besides capacity.

MR. KELLY: If I could close out with a yes or no question, I think I know the answer but I'm not sure I know. So that's why I want to ask. Some of you here this morning where virtually all the panelists urged a centralized capacity market be a requirement, at least for the Northeast if not for the whole country.

For your areas of the country, would you, yes or no, want to see a centralized capacity market requirement in the FERC rule?

MR. WAHLE: No.

MR. RILEY: No.

MR. RANDAZZO: No.

MR. HUNTOON: Yes.

MR. HEAD: No.

MR. CALDWELL: I think yes.

MR. KELLY: Thank you very much. And it's been a very helpful panel, more than you know. And we will take a break for 15 minutes and resume 15 minutes from now.

(Recess.)

MR. KELLY: Welcome back, everyone. If you could all take your seats, we'll get started. we have a truly outstanding panel of folks for the late afternoon. And I'm going to just get right into it.

Our first speaker is The Honorable Thomas Welch, the Chairman of the Maine Public Utilities Commission. And Chairman Welch, if you'll give us your views, we'd appreciate it.

MR. WELCH: Thank you. I appreciate the opportunity to be here. And I will not restate the proposal that I've offered but instead make an effort to answer one of the questions you've asked on a number of occasions today, and that is what it is that we would urge the Commission to do.

And I put it in really two categories. First, I think there's a set of questions the Commission should answer very quickly, and I have a few suggested answers. And then next there's a set of questions which I think the Commission can defer a bit.

The first question is, is there going to be one path or many? And frankly, rather than get into that debate, I'll just say the rest of my comments are addressed to regions that have wholesale and at least some retail competition.

Second, I think the Commission ought to recognize that the benefits to the market and to reliability of capacity adequacy are regionwide, so the costs should be too. The implication I think is that the link between particular load-serving entities and any particular level of obligation to obtain sufficient reserves should be cut completely.

Third, I think the product that's being sought ought to be defined in terms of what it does rather than what it is. And I have sort of an inelegant definition of a generic product. And that is that it's a credible commitment confirmed by performance of delivery on specific terms of an increase in the difference between the load and the resources available to meet the load over a defined period of time.

I think that the RTO ought to be given the responsibility to acquire a variety of products in separate auctions. A product needed to meet demand on ten-minute notice should not be lumped with the equally important but significantly different product that you need to provide energy or reduce demand on a persistent basis on average over time.

And I think, incidentally, this kind of product differentiation can accommodate one region's needs for additional resources in non-peak periods in a way that other regions might not need to.

I think the fourth thing that the Commission ought to do quickly is to establish that in any market that crosses state boundaries, the Commission itself must be ultimately responsible to ensure that resources are significant for healthy markets and reliable service.

I also think there's a second set of questions as to which national consistency may be less important. For example, what should the specific mechanics be to acquire the resources that are needed in an efficient way? What kind of auction, with the details of payment, security for performance. And also the particulars of the process by which the RTO assesses the particular level of need for any particular zone.

So I think so long as the Commission doesn't see significant seams emerging in this context, the Commission could allow significant variation among regions with respect to some of the answers to those questions.

And, therefore, as to those various possibilities, the Commission ought to be clear on the objectives but need not prescribe at this point details. The objectives would be things like an inclusive open process, the collection and distribution of money that provides the market liquidity to actually get things built.

The Commission might also require or indeed sponsor various kinds of tests to ensure that whatever mechanism is put together isn't subject to the kind of gaming that some of us have difficulty predicting.

And to me, those particular issues open for a compliance for a filing with a date to be set by the Commission so that the RTOs who will be bringing back the proposal consistent with those particular objectives.

Thank you.

MR. KELLY: Thank you. The next speaker is The Honorable Robert B. Nelson, Commissioner with the Michigan Public Service Commission.

MR. NELSON: Thank you. I want to thank the

Commission for allowing me to testify today on an issue that affects not only my state commission but also the ability of electric industry as a whole to develop the infrastructure necessary for a reliable transmission system in this country.

There's no question, in my view, that differences among states in reserve margins, resource adequacy requirements and the existence of retail access programs dramatically affect the ability to create a regional resource adequacy requirement.

However, it is not only possible, but necessary to accommodate these differences in connection with the creation of an overall resource adequacy requirement for each ITP under the auspices of the RSAC.

Differing state requirements for resource adequacy and reserve margins not only can be accommodated in my view, in both states with retail access programs and those without, but they can complement the regional requirement as well.

Even states with very rigorous resource adequacy requirements and no retail access programs can continue to administer these requirements without contravening the regional resource adequacy requirements envisioned by the NOPR.

States with reserve margins mandated by their commissions or by their legislatures that exceed the 12 percent minimum reserve margin required by the NOPR, or the reserve margin established by the RSAC, should be allowed to follow their mandates. The Commission should take steps to ensure that the load located in such a state will be responsible for any additional costs that would be required to sustain this higher level.

The fact that the NOPR would require all LSEs to achieve a 12 percent reserve margin would enhance Michigan's ability to create a workable retail access program. This is so because Michigan utilities have maintained a 15 percent reserve margin in the past, but we have this new entity called alternate electric suppliers created by our new restructuring law, and they are not required to maintain the same level of reserves.

Therefore, we support the imposition of reserve margin requirements on all LSEs, which in Michigan would include these alternate electric suppliers, subject to the consideration for phasing in these requirements to avoid it becoming a barrier to entry, and also recognizing the effects of load migration.

We share FERC's belief that it is crucial for the SMD to incorporate demand-side response as a vital mechanism to strengthen competition as well as to provide assistance with market power mitigation. Demand-side response resources must be effectively relied upon to moderate energy prices both in the short run through participation in a spot market bidding auction, and in the long run as a viable resource option to generation and transmission expansion.

In particular, it would be important to establish appropriate mechanisms to evaluate and verify the validity and reliability of demand-response resources so they can stand on equal footing with supply and transmission options.

Twenty years from now when this country looks back and recognizes the substantial benefits that SMD provided this nation's economy, I believe the states with retail access programs and those without such programs will heartily thank this Commission for including resource adequacy requirements in this proposal and reaching out to the states and other interested parties in the process.

Thank you.

MR. KELLY: Thank you. Our remaining speakers, as in previous panels, are listed in alphabetical order by last name. I don't know if anyone's noticed that. And just to show you the new, flexible FERC --

(Laughter.)

MR. KELLY: We're going to start with David Velazquez and work our way through Richard Campbell. Mr. Velazquez?

MR. VELAZQUEZ: Thank you, both for myself and on behalf of Edison Electric Institute and the Alliance for Energy Suppliers, I want to thank the Commission for the opportunity to be able to talk to you about this very important subject.

EEI and the Alliance believe that a resource adequacy requirement is an essential component of the SMD and fully support its inclusion in the SMD.

What I wanted to do briefly is highlight some of the key principles that EEI and the Alliance believe are important to be included in the resource adequacy requirement, and also talk a little bit about some areas where we believe that the adequacy requirement is laid out in the NOPR could be improved.

As I talk about the principles that EEI and the Alliance see as essential to a good resource adequacy requirement, two things have come out very clear in EEI's conversations with its members.

One of the principles is that states have always had a tradition role in establishing resource requirements, and this new process, whatever it is going to be, needs to continue to have them very involved in that process.

Secondly, this is not a case where one size fits all, and there needs to be allowances for regional variations, as necessary. In addition to those two key principles, resource adequacy and the market mitigation measures that are being contemplated are very interdependent and can't be considered independent of one another, and they need to be developed together.

I believe it's very hard to have a discussion of one of those, without having a discussion and understanding of what's happening with the other.

We also believe that it should be a simple a mechanism as possible and that it should be done on a regional basis. This is not something that should be done state-by-state or be done completely prescriptively on a national basis.

We believe incentives are highly preferred over penalties, and we should look to markets for solutions wherever we can. It should be a longer-term forward obligation, and whatever mechanism is decided on, should hold all the participants accountable in a fair and nondiscriminatory manner.

We have heard somewhat today about the issue of leaning or free riders, and EEI does see that as an issue that needs to be addressed.

Finally, it's necessary to ensure that all the resources are real, however you want to define that, and also deliverable.

As EEI has looked at the resource adequacy requirement that has been laid out, there are a couple of areas that we would like to comment on where we think that it could be improved.

One is that especially in areas where there is significant retail choice, load curtailment will not work, given the state of technology today and how that technology is deployed in the marketplace.

There are a couple of issues with penalties. We need to ensure that penalties can't be avoided by parties, and also that the penalty that has been proposed, does not have a relationship to a market scarcity-based clearing price.

We also believe that in imposing a forward obligation, it will be necessary to make sure that there is an adequate market mechanism to address that as well, that the two go hand-in-hand.

Finally, I'd like to point out that EEI's positions are still developing on this matter, and EEI is continuing to have discussions with its members in order to reach consensus, and although at this point EEI has been able to reach consensus around some of the broad principles or the broad principles that I have talked about, EEI has yet to reach a consensus on a specific proposal that all its members could say best accomplishes the goals that they have reached consensus on. Thank you.

MR. KELLY: Thank you. Did I pronounce your name correctly?

MR. VELAZQUEZ: It's Velazquez.

MR. KELLY: Thank you. Okay, our next speaker is Lynn Sutcliffe, Chairman of Praxair Energy Solutions, and he's speaking on behalf of the National Association of Energy Service Companies.

MR. SUTCLIFFE: Thank you. It's a pleasure to be here. I thank the Commission for the opportunity to appear. I am representing the National Association of Energy Services Companies, and our members are the ones that are the primary suppliers of distributed energy resources.

By that, we include energy efficiency, load management, onsite generation, with or without CHP, combined heat and power, as well as demand responsiveness.

I think it's important to recognize that there are many, many kinds of distributed energy resources, and we believe that each one of those resources is capable of contributing to the resource adequacy of a region or of the country.

I think it would be fair to outline the NAESCO position, again, with the caveat that we haven't vetted this with the entire membership. We were meeting last week for a national meeting, and we did have some discussions on this, but let me outline the following:

First of all, we would support resource adequacy standards. By that we mean mandatory federal standards that would allow for some regional variation or regional accommodation, but nevertheless, mandatory federal standards.

All sources, supply and demand resources should be eligible for consideration in a resource adequacy proposal.

There should be recognition of both permanent demand reduction, primarily of the kind that you would see in energy efficiency, and immediate or short-term demand response or demand reduction. And I think it's important to keep in mind that there are two types of resource adequacy contributions here.

One is a long-term demand -- permanent demand reduction, and the other is the ability, sometimes within the same technology, to also meet an immediate or very short-term demand responsiveness.

I think that oftentimes the discussion of demand responsiveness concentrates or demand resource concentrates on the latter and ignores the former, which it should not do.

We think that in that connection, you should try to distinguish between permanent demand reduction, and short-term demand reduction, and perhaps have some allocation for short-term demand reduction that has a certain additional value from an insurance policy standpoint, price suppression standpoint.

And, finally, we believe that it's essential if you're going to stimulate demand resources, that you set a long-enough term of payment, so that the industry can respond, can get its customers that it depends upon to participate, to respond, to initiate either permanent demand reduction or temporary demand response.

Finally, I would simply like to point out that there are some exciting new technologies, both through the IT environment and others, that can contribute substantially to the resource adequacy needs of our country through the distributed energy resource mechanism. Thank you.

MR. KELLY: Thank you. Our next speaker is Roy Shanker, who is a participant in the Northeast Joint Capacity Adequacy Group.

MR. SHANKER: Thank you. I was asked to appear here representing myself as a stakeholder in that process. The discussion you heard this morning by Dave LaPlante basically represents a proposal I put forward to that group about a year ago.

And rather than go through it in detail again, I might summarize it at the end. I think what might be advantageous is to talk a little bit about the Commission's proposal and what I see as the advantages and disadvantages, because I think those lay out the issues that set the context for understanding why a proposal that was put forward in the Northeast ISOs is responsive to what the Commission is looking for and is a good solution.

The basic benefits and advantages that I see are that the SMD proposal has a strong recognition of a need for adequacy. There's a direct linkage to the historic state and regional adequacy requirements.

It recognizes forward-looking obligations, a key element in getting elasticity of supply into the market. There is recognition of the locational nature of adequacy facilities. There is a recognition of a significant change that will come about because of an interaction with the long-term planning capacity benefit margins and a recognition of the need for deliverability among those resources.

Another list of the advantages would be the recognition that this is an insurance policy. There is a need for enforcement. It's not a voluntary standard. We are doing something here to deal with free riders. We are doing here something that is a second best alternative to a clear market energy price solution.

It is not voluntary and you must force this process to work. The positive element is the recognition that all resources should have an opportunity to participate on a relatively level field. That is, to the extent we can make them equivalent, they should all be there, be it supply, demand, or transmission.

There is a need for audit and verification as recognized in the NOPR, a recognition of the potential role of a market-based implementation, which is exactly what we have put forward, is also recognized.

And then a strong link and acknowledgement of market mitigation, that is, in the total context of the NOPR, we're doing a number of things that have basically suppressed price and removed scarcity. There have to be implementations that allow for the recovery of those funds with other mechanisms.

And the resource adequacy requirement and the associated ICAP or reserve markets or adequacy markets, whatever we're going to call them, have to play a role in making up that missing money.

There is significant disadvantages and problems with the proposal, as well. One of the most basic that troubles me is that it continually mixes planning concepts with operating concepts.

It links the notions of adequacy with things like CRRs and real-time performance, and penalties, and that's really not appropriate. I think that if we get into the notion of how planning is done, it becomes clearer and clearer that that's an inappropriate mechanism.

The penalty structure, as I said, is linked to operations and not adequacy. The process does not work well, and it is probably unfeasible with retail access.

And I think probably that the worst thing that can occur is trying to force all of this to work through a CRR and retail bilateral market mechanism. It's very harmful. It does not assure adequacy; it encourages, and actually, I think, almost assures an inefficient market.

It penalizes the small players, and probably exacerbates the problems and potential for market power. Thank you.

MR. KELLY: Thank you. Our next speaker is Craig Roach, a partner in the Boston Pacific Company, appearing on behalf of the Electric Power Supply Association.

MR. ROACH: Thank you, Kevin. I appreciate the opportunity to speak today. EPSA strongly supports the resource adequacy requirement concept. I believe it's going to help promote the two primary goals in standard market design.

It's going to promote infrastructure investment, and that's going to assure reliable service for consumers, and it's going to promote bilateral contracts, and that's going to keep consumers out of the spot market.

We also very much appreciate the fact that the Commission and the Staff recognize the crucial interplay between resource adequacy and market power mitigation. That interplay can be spelled out with several points:

First, it begins with the political reality that price spikes are not going to be acceptable. It turns then to the market reality that price spikes are a natural part of spot markets, and they do too good things:

First, they drive generators to build new generation, because in that price spike lies most of or some of the return on capital, especially for peaking plants. It also drives load-serving entities to sign bilateral contracts. The reason they sign them is to avoid the price spikes in the real-time market.

If we were to cut away the price spikes, artificially, take them away artificially without compensation, there is a fear that two bad things would happen: First, that we would artificially entice load-serving entities into that spot market and cause overexposure to spot market prices; and, secondly, that we would discourage generation investment and potentially cause a shortage.

We have all learned that overexposure plus shortages equals a crisis. In terms of the concerns with the specific proposal, there are some concerns with the enforcement mechanism.

The Commission wants to rely on real-time penalties and real-time curtailment. While that is all very justified, there is a concern that the penalties that you will have to charge, will be as high as the price spikes that we're trying to disallow, so that they wouldn't be politically acceptable.

We also have a real concern that curtailment is not politically acceptable. It's certainly something that we don't want to see.

In terms of a recommended enforcement mechanism, I think the general principles are that we'd like to see resource adequacy demonstrated well before real-time. We'd like a market-based approach to enforcement.

We think there are several good proposals before you; each has different priorities; each emphasizes a different goal, and that's how you can think them through.

EPSA doesn't have a consensus either. They have pushed hard on it and continue to do so. Thank you very much.

MR. KELLY: Thank you. Dave Nevius is Vice President of North American Electric Reliability Council.

MR. NEVIUS: Thank you for the opportunity to be here today. First and foremost, NERC strongly supports the Commission's intent and your justification for establishing a minimum resource adequacy requirement in its proposed standard market design rule.

If a standard market is the goal, more uniformity is needed in minimum resource adequacy requirements. However, NERC finds that the fixed percentage resource adequacy requirement proposed, while easy to understand, will not ensure a consistent level of reliability across the grid.

And I think we heard some previous panelists speak to that issue. We recommend an alternative approach be considered, and that is that a minimum resource adequacy requirement should be based on a consistent technical criteria that uses one or the other of the probabalistic approaches and indices to recognize different system characteristics that exist in different regions.

These indices can take into account, capacity-constrained systems, energy constrained systems, the performance of supply-side and demand-side options, different types and sizes of generating units, different demand patterns, and even different customer costs related to outages.

Uniform technical criteria based on these probabalistic indices, which are similar to those used by the industry for over 40 years, will yield a more consistent minimum level of resource adequacy across the country, versus using a deterministic approach with a fixed percent reserve margin.

Entities responsible for resource adequacy, whether they be states, RTOs, regional reliability councils, or regional planning bodies, could adopt resource adequacy levels higher than the minimum. However, to avoid one region leaning on another for its reliability requirements, no region or area should be allowed to adopt adequacy requirements below that minimum.

Most of the NERC regions already have minimum resource adequacy requirements that are based on probabalistic reliability indices. One of the most common that you have heard of today is the loss-of-load expectation, which requires resources sufficient to achieve an index of equal to or less than 0.1 days per year, often stated as one day in ten years.

This is the index used for example, in the Northeast Power Coordinating Council, which requires each of its areas -- New York, New England, Ontario, Quebec, and the Maritimes -- to demonstrate compliance with this index.

Similar probabalistic indices are also in use throughout the industry, including such as expected unserved energy, dependence on supplemental capacity resources, which is used in the ECAR region, loss of energy probability to take into account, energy-limited systems, and frequency and duration of capacity deficiencies.

Many state commissions already look to these minimum resource adequacy requirements established by the NERC regional councils. We believe that given the highly technical and reliability-related nature of this endeavor, the Commission should ask NERC, as a reliability organization, to develop the uniform technical criteria and indexes for minimum resource adequacy requirements.

Those entities responsible for resource adequacy could then use these uniform technical criteria and indices, along with related guidelines and common definitions, to develop the necessary enforceable requirements appropriate to meet their needs.

It looks like we're counting up again. I'm over time, so I'll stop there and take questions. Thank you.

MR. KELLY: We'll give you a grace period, if you want to sum up.

MR. NEVIUS: There is just one other point: Many of you know that NERC maintains a generating availability data system, which is a database that collects information according to a standard format.

It's based on IEEE Standard 762, which is used worldwide. We collect data on over 4,000 electric generating units.

The Commission used to require the reporting of these data by generators. It was part of a fuels form, FERC Form 580. This is back in like 1984.

That's no longer a requirement, as I understand it, and we suggest that the Commission may want to consider reinstituting that mandatory reporting of generating availability to the GADD system, as had previously been the case. Thank you.

MR. KELLY: Thank you. Richard Campbell is Director of Energy and Technology at American Forest and Paper Association.

MR. CAMPBELL: Thank you. The Forest and Paper Association is a national trade association of the forest, paper, and wood products industry.

Our industry is the nation's largest cogenerator of electricity, accounting for 43 percent of onsite electric power generation. This onsite generation also represents almost 85 percent of renewable energy used in the manufacturing sector.

In addressing the issue of resource adequacy under the proposal for standard market design, the FERC seeks to assure that sufficient electric power generation will be available to serve projected needs. The American Forest and Paper Association agrees with FERC in that a standard resource adequacy plan should exist regionally. It should be designed in coordination with the appropriate state authorities, and it should be subject to FERC approval of interstate or interregional matters.

Any resource adequacy measures finally adopted should be in the form that would allow them to be market-drive, aided only when necessary by regulatory intervention. Demand-side measures should be encouraged and count equally towards any adequacy requirement.

ITP rules should be designed or amended so that industrial cogeneration facilities whose power sales may be intermittent into wholesale markets, may supply wholesale power to the markets without undue burdens on industrial production processes. We are manufactures, not merchant power producers.

Outside control can disrupt productivity and put worker safety at risk. For decades, the forest products industry has provided the majority of its own industrial energy needs. Many pulp and paper mills have run their own paper production processes, using electricity largely supplied by mill-operated, onsite electric generation.

Regional transmission organizations have typically required that interconnected generating facilities, including onsite cogenerators, be under the control of the RTO, even if the generator is not making sales into the market, that it is merely interconnected in its transmission grid.

Cogenerators that may have power available to sell into the wholesale markets, either intermittently or constantly, should not be treated the same as merchant power plants. Additionally, some RTOs view all electricity consumed by a self-generating customer as being delivered from the electrical transmission grid, rather than recognizing that the cogenerator does not use the grid services, nor consume the power generated by its own onsite generation facilities.

Because a cogenerator only provides excess on net volumes with electric power to electricity markets, using the gross generation potential of these facilities and studies for interconnection, safety, or transmission, could create a false estimate of available capacity.

A net capacity approach is the only way to eliminate potential resource planning problems. Thank you for allowing the AFPA to speak at this meeting.

MR. KELLY: Thank you all. Our habit is going to be to turn your cards up if you'd like to address a question. Alice?

MS. FERNANDEZ: It looks like I get to go first. I guess I'd like to explore a bit further with Mr. Nevius as to what you are proposing that NERC would come up? I mean, is this that there would be -- NERC would come up with either a national standard or standards for each of the reliability regions, and that it could then be something that each RTO would have to have a program that would satisfy that?

MR. NEVIUS: I think what we're trying to convey here is not a standard. We've already said that NERC would not set standards for resource adequacy, but we think that we could help facilitate, as some of the earlier panels suggested, some agreement on common approaches.

Not all probabalistic indices work equally well in all situations. Obviously, in the Pacific Northwest, a loss-of-load expectation has almost no meaning. But there are some common definitions; there are some accreditation rules, and we could help facilitate some more common, more uniform rules that would apply in similar situations.

So, again, not to set standards, per se, but to help facilitate a more uniform approach to applying some of these approaches.

MR. KELLY: Dave, that confuses me. The proposed rule, except in one place, seems -- just refers to a resource adequacy requirement, without specifying what it is.

At one place, in defining a minimum, it names 12 percent reserve margin, but quickly has a lengthy footnote that says, you know, that's just one measure of reliability, that you can use reserve margin, capacity margin, loss-of-load probability, or other measures that the region may choose.

It seems to me that there is a lot of discretion there, and are you saying that regional discretion should be overcome by a NERC standard? And yet you say you don't want NERC to set the standard? So I'm not quite getting it.

MR. NEVIUS: I think there can be some regional discretion here. I mean, obviously, some folks have been quite successful in working with certain indices like loss-of-load expectation, and applying them.

But, for example, what is a loss of load? There was one power pool before it became an ISO, that used to consider a voltage reduction as a loss of load, and then somewhere along the way, they decided that it was no longer a loss of load.

Now, this may be perfectly fine, but if a neighboring ISO makes a different assumption, there are going to be inconsistencies. So the bottom line is, you will not have equivalent reliability if you have two different applications.

We're not going to suggest what the one perfect application is, but we think we can work with RTOs and states and others, and, of course, with the regional councils, to come up with some more common understanding of these indices and how they are applied, common definitions, guidelines, and so on.

MR. KELLY: But the discretion in the rule is adequate, as far as you're concerned?

MR. NEVIUS: Well, to the extent that you're not stuck on a fixed percentage or a deterministic standard, because that will definitely not give you a consistent level for minimum reliability.

MR. KELLY: You read it as requiring? I read it the opposite.

MR. NEVIUS: I didn't read it as requiring it, but certainly that was what was suggested in the text, and the explanation was in the footnote, so we felt obligated to comment that a fixed percentage approach would not be our first choice.

MR. KELLY: Okay, thank you. Roy?

MR. SHANKER: Just to follow upon that, I think it's stronger than that. I think you really don't want a fixed percentage approach.

There are other things going on in the structure, particularly with respect to planning capacity benefit margins, the interaction of the size of the footprint of the ISOs, encouragement of a larger footprint, all of which point you away from fixed reserve margins, and tell you that you are going to miss one of the key things you're going after, unless you use probabalistic standards.

In fact, use of a deterministic standard would discourage a larger footprint, and the way we've set up the rest of the things within the NOPR, would -- a probabalistic standard would encourage a larger footprint.

So all of this is integrated, and so you have to see this altogether. And so if you want to meet the other goals, I think it's imperative that you sort of -- it's interesting to say summarize things as 12 or 18 percent, but underlying all of the -- at least the Northeast areas that I'm familiar with, are the probability studies that then get translated into a representation. But it's a probabalistic standard underneath.

MR. KELLY: I think I agree with that. Just maybe for purposes of clarity, my reading of the proposal is that each region is free to devise its own resource adequacy requirement. And there is no suggestion that it should be a fixed reserve margin.

I mean, it's frequently the case that reserve margins make for easy examples, 16 percent, 18 percent, minimum 12 percent, but I thought we took some pains to talk about that there is absolutely no obligation to use a particular measure of reliability.

And that seems to be a concern of many people, and that's why I raise is. Yes, Commissioner Welch?

MR. WELCH: Let me add a couple of things on the question. One, it seems to me that while it -- the notion that a region ought to have some independence with respect to what the particulars are of its reliability requirement, makes some political sense, but I'm not sure how practical it is, because there isn't anything called a region that is a political entity.

So at the very least, I think that this Commission needs to establish the criteria by which it will sort through the disputes when you get somebody from a region saying it ought to be a probabalistic test with particular characteristics, and someone else saying it should be a different probabalistic test.

The second point here is that although -- there is a great deal of very useful stuff already there. I think that stuff in New England the Northeast is actually very good, but reliability is really only one of the components or only one of the reasons for having the resource adequacy.

8

The other one is, you want to have, in markets that are competitive, a sufficient surplus, so that the markets actually function well. If they are always functioning on the margin, they will almost never function well.

And it may be that each region has to take a careful look, and FERC needs to decide how to decide about each region's look, whether some departure from the number that comes out of the algorithms and the probabalistic tests is necessary to ensure this second function, as well as the first.

MR. KELLY: Commissioner Nelson?

MR. NELSON: Yes, let me just add to that. I think the NOPR indicates that there's a hope that the states will get together in a given region and come up with their own standards, and that there is a possibility that that won't happen.

And I think not all the regions are as harmonious as the Midwestern state commissioners are. And so we have to anticipate, and I think that, in my view, it's this Commission's responsibility to take over at that point. I know that there are other suggestions that have been made today about that, but it's my view, as Tom indicates, ultimately it's FERC's responsibility to develop that kind of standard.

MR. KELLY: I'd like to follow up on that in relation to something that Mr. Valazquez said.

We called for a greater state role than what the NOPR proposes, and the NOPR proposes as state role that seems to be a little -- you seem to be calling it a little less of a state role than what the NOPR proposes, if I read you right.

The NOPR says that the states should pick the length of the planning horizon, should pick the level of reliability, however expressed as a reserve margin or loss-of-load probability, and that if a load-serving entity fails to meet a resource adequacy requirement in the first instance, the ITP should report that to the state, with the presumption that the state would take some action with regard to seeing that they do meet it.

So I guess there are two questions: One is a question for Commission Nelson, as to whether that is too much of a state role, and the question for Mr. Velazquez is, what additional state role would you like to see that's not already proposed?

MR. NELSON: If I can go first, I didn't mean to imply that what NOPR said is too little for the states. What I'm saying is, there is this concept that if we don't get together, and we don't develop a planning horizon for the region, or don't develop adequate standards, then somebody else has to step in, and then the NOPR is silent as to who that should be.

And I'm saying that at that point, it should be this Commission. But I'm fully willing to take on those responsibilities that you just outlined, Kevin, in our region, at least.

And I think it goes to the point that maybe we should strike the word, "advisory," from the RSAC, because those functions are not advisory, in my view.

MR. KELLY: I agree. I think we all consider it struck.

MR. VELAZQUEZ: I think we've talked about this as a regional issue, which certainly we believe that it is, and therefore you do need this coordination between states, and states need to be involved in the process.

I guess what we saw was FERC setting some guidelines around how this market would work, or how the resource adequacy would work. And then because it is a regional issue, not only do you have the states involved in it, but you also have the ITP and all the other stakeholders, and that the issues around this within the guidelines that FERC establishes, kind of get resolved on a regional basis.

You know, FERC could set guidelines that say, you know, it's got to be a forward obligation; there has to be provisions to prevent leaning on others. It needs to be market-based, whatever. There could be a whole list of those, and that's more of what we saw the role of FERC being.

MR. KELLY: Is there a specific additional state role that EEI or you would recommend?

MR. VELAZQUEZ: No.

MR. KELLY: Thank you. Craig Roach.

MR. ROACH: Just a quick comment on the state role. You know, I think the ITP will take a lead in this, but I think that well after these decisions are made on the three things you mentioned, there continues to be this collaborative effort.

You know, I think it's important to see that the states do, and the entities regulated by the states, have a significant effort in terms of resource adequacy. I mean, they care that the lights stay on.

And so the ITP is going to want to build on that effort, and I think that point should be made. And the way they build on that effort is to overlay a regional framework.

And I think if it really turns out to be collaborative, that regional framework is going to pay off in better decisions, maybe missed opportunities that are now identified, maybe even lower reserves for a local area, because the regional reserves take care of it.

I think it will help the ITP to know where the states are going, so it can accommodate where the states are going with actions on what it does, on transmission. So I think that collaborative effort is the spirit we want to be, and it really is not reinventing the wheel.

MR. KELLY: Ed?

MR. MEYERS: And as we all know, the states are particularly skilled at working in demand-side measures, as well as traditional supply-side on the generation transmission side, and there is a history there.

And Commissioner Nelson, in his testimony, talked about nurturing these regional entities. And I'm wondering what FERC can do, other than what's in the NOPR so far in terms of nurturing these entities and requiring some sort of a relationship between the RTOs and the regional state committees? That's for anybody.

MR. CAMPBELL: Speaking for the industrial cogenerators, I think that where there is a disagreement with state authorities or the regional authorities, that FERC can act as the final arbiter, so that's a very valuable function.

MR. KELLY: Commissioner Welch?

MR. WELCH: Yeah, I'll answer that question, but also the one before, because my view is a little bit different than Commissioner Nelson's.

I think the state role laid out in the NOPR maybe is too much. I think the state's traditional role has been one that is closely tied to a world of vertically integrated state jurisdictional electric utilities.

I haven't lived in that world for three years. I don't have someone to whom I can point and say you take care of load. I do not regulate in any real sense, the default supplier in the state or any other supplier.

I think if FERC continues to move down the path towards genuinely competitive markets, I think it needs to recognize and make as politically palatable as possible, the fact that once the deciding entity over a market cannot be smaller than the market, and there is no state that meets that, with the possible exception of single-state markets, of which there are very few, I think what the states --

There needs to be a significant redefinition of the role of the states. I think the states are good at some things and not so good at other things.

And we can certainly continue to provide and answer Ed's question. Whatever expertise we have, a lot of activity on the demand side, conservation and things of that nature, but I think in terms of the fundamental decisions about what is the set of rules that is needed and what are the set of criteria that are needed to make a multistate market work --

I don't think that saying this is the state's responsibility and we'll just back you up, is any different than saying it's our decision and we'll let you pretend it's yours for awhile.

So, I think it's -- you know, I think there are a number of state commissions that are willing to recognize that the roles have shifted, and I think it would be a useful thing to articulate.

MR. KELLY: Mr. Sutcliffe, and then Commissioner Nelson.

MR. SUTCLIFFE: I would challenge the supposition that the states are the prime movers for demand energy resources. The reason that I challenge that is that there is very much of a spotty record amongst states.

Some have put their money where their mouth is; others have put their mouth and only that, where demand-side management should be.

If you're going to move under the SMD, then I think you should carefully consider using the ITP and the RSAC mechanism to establish standards, particularly standards in the distributed energy resource arena.

I think that it would untie some of the political problems, some of the interest of the existing distribution companies for running KWH through their wires as much as possible. I think there just are a lot of things that recommend taking the approach that Chairman Welch had in his paper, of putting the ITP there, making the state involvement very much of an advisory and very participatory to the result of getting a diversity and the best kind of resources to meet the adequacy that the region determines.

It also allows the business world to now deal with perhaps five or ten entities, rather than 50 in trying to understand what the rules are, in order to deliver the distributed energy resources. And that is not insignificant when it comes to trying to meet and participate when you're a diverse and fragmented industry that is looked upon to provide resources that can very much help the national energy policy.

MR. MEYERS: Commissioner Nelson?

MR. NELSON: Yes, as you all know, in the Midwest, we have a wide variety of different states in terms of where they are with retail access. Some states, like Indiana and Wisconsin, will probably be years away from retail access, if they ever get there.

And I think that brings up the question of how do you deal with those states who have some pretty rigorous requirements right now, like Wisconsin, when they have entities, load-serving entities that cross boundaries with retail access states like Michigan.

I think they're not going to give up on their state requirements. I know it's good that Tom is moving ahead in the new world, but those states are not.

So in order to deal with this issue, I think you have to have a regional approach; you have to have an attempt, at latest, by the states -- all the states in a region, retail access and non-retail access, to work on developing these standards. And if they can't do it, they can't, but I think, in answer to Ed's question, that's the best way we can develop a relationship with the ITPs in that area, is to help develop those standards, and then using those ITPs, to develop the technical expertise that we need.

MR. MEYERS: Mr. Shanker?

MR. SHANKER: Yeah, I'd like to split my answer, I guess, into two pieces: I think in the context of the adequacy discussion, I think the role should be less. The good participation at the state level, I think is a judgment about what is the level of reliability that they want to see in their markets, in aggregate?

And that's a very appropriate function, and I think that's -- essentially, it's a political function, in a way, and I think that's really good. But I have a feeling that we would all be best served if it stopped there.

As an empirical matter, when we go into the day-to-day function of the markets, a major problem has been a mismatch between the wholesale market designs and the retail market designs.

And the guidance really should flow from the wholesale markets to the retail markets. There are some, I'm sure, legitimate political and adjudicative reasons why some of the retail programs are the way they are, but we have spent, at least in the Northeast, inordinate amounts of time, probably, seriously, half to two-thirds of our time with the tail of bad retail rules wagging the dog of trying to be proper retail market designs.

We have only recently gotten over that hump. For the first couple of years, that was what it was all about. When you do things like put in polar responsibilities and nodal pricing and LMP, and give people all the right price signals, and then embed that with a system with provider-of-last-resort responsibilities and fixed retail prices, you see people squeal and try to change the rules of the wholesale markets.

And at some stage, that has to be reconciled. And if you're looking for an area for better coordination, that's an area that we have to address.

It's a horrible experience, this seeing people with very legitimate concerns, being squeezed at the retail level, trying to change wholesale rules that they know are correct, but they're acting in their own best interest to protect their financial stakes in the world, simply because they are squeezed on the other end.

MR. MEYERS: Just a very quick followup. A speaker this morning talked about demand-side responses, not so much in terms of changing the wholesale rules, but in terms of a load modifier, to use his terms, which implies a long-term planning process, which takes into account, not just demand response, but also perhaps aggregation of DG, and certainly energy efficiency to try to come up with a multiyear plan that actually shapes the load curve over time. Do you buy that?

Do you buy that as a state role?

MR. SHANKER: Sure. The structure we talked about would allow, either as an load modifier or as an independent supply if it was properly qualified, demand-side management to participate.

I personally think having a long lead time is consistent with that. I heard some people say that they thought it was inconsistent with that.

The proposal that we were talking about for the region also has reconfiguration auctions that would occur on a regular basis up to the time of delivery, which would allow demand resources to be very flexible and respond in balancing out variation in people's expectations.

And the reality is they become nice smoothers in the process. But you can't let something that might be three, four percent of the total process which might indeed be more responsive on a short-term basis, again wag the dog of things where you're trying to get supply elasticity for four- and five-year capital projects that are creating the other 97 percent of the supply.

MR. KELLY: Commissioner Welch?

MR. WELCH: Well again, it is a question of--I think the answer didn't quite match the question. Because the question was: Should this be a state role?

And the answer was: Yes, there ought to be a role for demand products.

But that doesn't answer the question of who should decide what the criteria are according to which a demand product is bid into the market. That cannot be a state role in a multi-state market. Because then you would get inconsistency from--people in the market wouldn't know what they could have accepted in the market if you have different states making a decision about it.

So I think again the state role is input in terms of expertise and experience and advice, and perhaps the tax stimulation within the states to get the resources built. But not, I think, having independent state authority over whether or not a particular kind of resource can be bid into the market in a particular way in the capacity market or the energy market.

MR. KELLY: The FERC NOPR suggests that there ought to be standards, for example, for what types of demand response programs can be bid into the market.

I ask the question about whether NAESB would be the right group to develop that. It may be a question for Dave Nevius. Is NAESB or NERC the right group for demand response bidding criteria?

MR. NEVIUS: I think at this point it's more of a market issue that the ITPs need to wrestle with in conjunction with the states. I don't know that it's an issue for either NERC or NAESB at this point.

MR. KELLY: Okay. Yes?

MR. WELCH: It goes a little bit back to how you define the "product." I don't think that FERC, or even the ITP or RTO, needs to decide in advance what particular kinds of configuration of demand, or what particular kinds of plants can satisfy the requirement.

If the product is defined as something that has a particular effect at a particular point in the future, there could be a lot of things that could do that.

One of the, I think, disadvantages of the FERC NOPR on this is that it links it to sort of existing physical facilities.

I think an ideal market would have all kinds of speculation be available so that if people simply had an idea about how they could satisfy this requirement and were willing to put up security that satisfied the ITP, that ought to be available.

So I don't think FERC needs to, or ITP needs to worry about in advance exactly why it is this is doing it so long as the product on the day it has to be delivered is delivered and that's what it's supposed to be doing.

MR. KELLY: We'll hear from Richard Campbell and then we'll turn to another line of questioning.

MR. CAMPBELL: Well with regard to demand side programs, I think what we have to look at is the tremendous opportunity to utilize existing reserves that industry has. Whether this is with interruptable contracts or with some other new type of contract vehicle, industry does have spare generation that sometimes is used for routine maintenance that could be brought online fairly quickly. And this is something that I think ought to be considered, also.

MR. KELLY: A question for Roy Shanker and then I think we are going to turn to a broader set of questions.

You said something that I thought I heard as the bilateral mechanism is very harmful.

Would you elaborate on what you meant by that?

MR. SHANKER: What I was trying to get to is that in a world in which there is retail access relying solely on bilaterals, it is a very inefficient mechanism. There is just too much information to be communicated.

You've created a situation where a 3 or 4 megawatt person, particularly in a forward seeking world, or a 5 megawatt guy just starting out his business, you're going to ask him to procure for three years in advance? It's just not going to happen. It is not a realistic business model for that person to be in.

On the other hand, for a central procurement to go out and buy with a transparent price the requirements for the entire system, there could be bilaterals embedded in that of course with contracts for differences, but to set a clearing price for a couple of years ahead for him to see to do his business plan, again that's very good.

So what I was trying to get to is that for small participants, a strictly bilateral market structure, coupled with retail, is a huge barrier to entry. And in fact one of the basic reasons I proposed the central auction was to get rid of this problem because it had been one of the nagging problems we had seen in PJM--more so than in New York--in PJM. This was a continual problem with the small LSEs. You couple it with polar responsibilities and there's all sorts of reasons why people don't want to release their capacity. So it looks like hoarding and it starts to look like market power problems.

You start looking for forward obligations, and small participants can't do it.

And then suddenly we take that all away from them by going to a structure that says somebody--you're going to get a bill. The bill is going to look like X with a little bit of forecast error associated to it in two years, and you are going to go and start signing people up.

And the entire intermediary process of entry for these kinds of participants goes away as a problem.

MR. KELLY: I see that point.

Let me ask you this: The proposed rule permits but doesn't require a central capacity market.

MR. SHANKER: Correct.

MR. KELLY: And that allows, say, the Northeast to have a central capacity market if it wants to, but doesn't force it on the South if it doesn't.

I think you walked in just after I did my little recitation this morning about what would you want to see in the final rule.

MR. SHANKER: No, I heard that.

MR. KELLY: You know, but it ranged from, you know, would you want to ban bilateral--well that's too strong.

Would you want your idea to be permitted in the Northeast and stop there, but not require it as a national rule? Or is it really the only way this is going to work? And it would have to be part of a national rule or other regions will eventually find that their markets are failing and have to be corrected?

MR. SHANKER: I think there are two or three points here.

One is, the political reality is you should let it be flexible enough so the Northeast can do what it wants, and other people can try.

The other lesson we've learned is that, regardless of what we say, some people are going to insist on trying things whether they work or not. So that means we should be flexible.

The third, or the fourth thing--

MR. KELLY: What we've learned is that if we let people try what they insist on trying, we can sometimes-- that will come home to roost at FERC.

MR. SHANKER: Right. The only mitigating aspect of why I would say not to mandate this is because I want a bilateral structure underneath this. I mean I want to encourage bilaterals.

The only reason I would say not to mandate this is that in a world without retail access, and in a world where LSE is synonymous with control area, your proposal works. Okay?

You have to sit there and look at it for awhile and say all the things I don't like about what's in the SMD pretty much go away if there's no retail access, if the party who is being penalized is a control area in an integrated company. You know, I can shut him off. I know how to penalize. I know how to load shed when the entity is a control area.

And if you're addressing that part of the world where we don't seem to have a lot of divestiture. We're basically all integrated companies, and there is no prospect for large divestiture in retail access, then, no, you don't need to do that.

So I guess that's where I draw the line. If you see this coming, though, with a lot of divestiture in retail access, it would be a huge mistake I think not to direct people toward some sort of a clearing auction.

MR. KELLY: We'll go to Mr. Velazquez, and then I think Alice is going to start a new line of questioning--

MR. MEAD: Could I follow up with one question, first?

MR. KELLY: Sure.

MR. MEAD: The basic question is: Is there a risk of stranded costs later on if there is a central auction?

MR. SHANKER: No. Remember, first off everybody has their contracts for differences, so it is the residual people who are being cleared in the auction.

We are going against the planning forecast quantity depending on whether we have a demand curve or not. Let's take the world without a demand curve for a moment. We are going to procure X on say 10,000 megawatts.

The forecast load turns out to be--the forecast load is 10,000 megawatts. The actual load turns out to be 10,100. We are going to adjust by 1 percent the allocation of what we procured. And so the billing determinants for anybody who is buying in that market, they're picking up the forecast error. So there is no stranded cost.

MR. MEAD: That is, if the ITP makes a mistake and buys too much--

MR. SHANKER: Or too little.

MR. MEAD: --or if it buys--it buys enough, but at a very expensive rate, so that later on before the real time, the other LSEs decide that they can buy capacity more cheaply, that those extra costs are just spread around and shared among everybody?

MR. SHANKER: There's two things. One is forecast error. Forecast error is socialized because we're essentially going to have a fixed set of billing determinants and a fixed set of costs. And if the actual determinants are larger, then we're scaling everything up or down.

The second question is: Are you going to second-guess yourself? The answer to that is: We're buying for three years forward. So the price today for three years forward is the price.

If next year it turns out it could have been cheaper, that's the way life goes. You can't judge imprudent or stranded a clearing auction widely publicized, no market power issues, that happens to be on the way up or the way down of the market. I mean, that's absurd.

MR. MEAD: How would you respond to the people who argue as an LSC that we don't want to procure 100 percent in advance because I'll wait till the month before to see exactly what I need and only buy that amount rather than having to worry about the forecast?

MR. KELLY: After you answer this, I do want to recognize the other cards that are up.

MR. SHANKER: The answer to that is, you are either into the reliability design for the market you're in or you're not. And so if somebody else wants to wait on spot, they're basically saying they want to be the free rider. They want to see if they can be the free rider. And you make a decision in advance as to whether you're going to allow that or not.

I don't think it is equitable in a mandatory insurance or a tax or a mandated market to allow people to do that. You set the rules, and if you're going to eliminate the free riding issue by obligating people to reserve reliability, then you go forward and you do it.

MR. KELLY: So you think the obligation should be forward, not real time?

MR. SHANKER: Absolutely. I think that's the only -- the overwhelming problem we're seeing for market power issues in this area is lack of supply elasticity and a lack of demand elasticity. The only way we're going to get supply elasticity is by giving people and opportunity to build into the obligations, and that means forward procurement.

MR. KELLY: Let's go to Mr. Velazquez.

MR. VELAZQUEZ: Maybe I'll start at the end where Roy ended with the whole issue about the question you had raised, and I would phrase it pretty simply that this is a reliability product and it's not a financial product in some ways, and that issue of having the ability or creating a construct that allows people to lean on others, or to gamble if you will, is not something that we would like to see.

The initial reason I raised the card, though, was I anted to go a little bit beyond where Roy went in saying that some of the need for not mandating a centralized capacity auction. It's kind of a political issue in that it's politically expedient to do that, that EEI would recognize that there are differences between the regions. There really are. And there's different -- each region is in a different place, and that that would argue very strongly as you look at each region to allow some difference and not mandate one specific procurement mechanism for that.

Speaking for Conectiv Energy, which lives in the Northeast United States, we like the idea of a centralized capacity market and think it will work well. I've been very involved in the JCAG process and supportive of it.

I make one other comment. Someone had mentioned the issue of stranded cost. And earlier we were talking about states and their involvement in the process. I think one other issue that can come up under certain regulatory constructs is the cost recovery issue and the need to have states involved in that planning process if there is going to be some requirement to buy off on some additional infrastructure, and how does that investment get recovered.

MS. FERNANDEZ: I was going to say, you gave me a great lead-in to the questions I wanted to get into. Today we've heard sort of varying answers on mechanisms from the various regions. There seems to be a lot of support for the concept of some sort -- assuring that there's adequate resources. But there are a lot of differences about how to do that.

So I wanted to get back to some of what I think Kevin brought up at the beginning in terms of what FERC should do in a final rule. Are there certain principles that should be enunciated that could apply across the country in all regions? There was some discussion of as to with capacity markets, is that something that should be an option but not a requirement?

Are there in certain states where there's been a lot of divestiture and there's a lot of retail access, the state commissions may not have as much ability to deal with these issues as in states where they're basically you're looking at vertically integrated utilities?

So I mean if you have the ability to -- or if you had the ability to write the final rule, what would you say in terms of what the requirement should be in terms of resource adequacy? It looks like we have a volunteer first.

MR. ROACH: I think FERC should go as far as it can go in taking major forks in the road, you know, just to start it out. I think obviously it's a big fork in the road to say we're going to have a requirement, and we would definitely encourage you to take that fork.

We think that another fork is to say that enforcement will be well before real time that you're going to assure resource adequacy well before real time.

I think another fork as you go down the road is that that enforcement will be market-based.

MR. KELLY: Could you explain that term?

MR. ROACH: Market-based?

MR. KELLY: As you use it in this context, enforcement is market-based.

MR. ROACH: It means that if someone is found to be deficient, if there's an assessment of resource adequacy for an LSE, that there's lots of proposals, but let me give you a couple of examples.

One would be that the ITP would hold an auction, basically create an opportunity to go out for that LSE and to acquire the resources. Some would say that that would just be an auction that they've accommodated. Another would be a deficiency auction which says, well, you really haven't come around. We're going to make you acquire the resources that make you sufficient. So a market of that sort.

MS. FERNANDEZ: Would a penalty system such as, for example, on the last panel, MAPP was discussing where if you didn't satisfy the requirement and you got to basically on an after-the-fact basis that you hadn't satisfied the requirement there would be a penalty based on some measure of what it would have cost if you had met the requirement, would that satisfy your test?

MR. ROACH: I listened to that. I think the threshold question is when do you want to do this? None of us want to be after-the-fact punishing for a curtailment. We don't want to be in that position. And so I think that there's a real interest in doing it beforehand to avoid curtailment.

But also there's a real interest in enforcing this well prior to real time because of the other major goal of resource adequacy, which is to encourage new investment. We need some time to do something. Real time is not sufficient time to build new assets. So you want to enforce this well before real time because you want to be promoting new investment.

MS. FERNANDEZ: I guess it's something like that you set up a penalty that everyone knows well in advance this is what the penalty is going to be, and it's going to be very high, and it's going to be so high that the utility is going to have problems at its state commission, or basically it's going to have problems if it ever incurs that penalty. So by telling someone well in advance, this is a consequence of your action, you basically use the penalty as a way of deterring the conduct, and you give someone an incentive to comply.

The other it seems like if you're getting into a capacity market is you take the approach of -- if someone doesn't voluntarily, doesn't come forward with the amounts by themselves, either in the traditional ICAP there was a deficiency penalty that was applied in advance. When we're talking about more of what's in the capacity markets in the JCAG, it's that the RTO would basically just procure them and send them the bill. And if they want to continue to be a member of the pool, they're going to pay the bill.

MR. ROACH: I think you lay it out well. Let's talk about penalties. Remember where we are in this discussion. And let me steal Roy's word about second best. We're in a mitigated world. If we let markets go unmitigated, uncapped, and a load-serving entity saw that market and faced scarcity pricing, that sort of thing, that would be a different story.

A market without mitigation is a different place. That's not where we are right now. And as I said in the beginning, there's a real concern that the penalties that are needed to get that kind of reaction are going to be as high or higher than the price spikes that we're saying are unacceptable.

So we're sort of forced back away from penalties on that reality that we're in a different world.

MR. KELLY: Can I just jump in here? From an economics and business point of view, I understand how -- what you're proposing. You're really proposing I think a mandatory purchase at a market-based rate is preferable to the penalty approach.

But in the legal and jurisdictional world, it's sure a lot easier to see FERC applying a penalty for a wholesale purchase in the spot market where FERC has the authority to set rates than it is to easily find for FERC the jurisdiction to enforce a mandatory buy provision. I don't know if that's entered into your thinking or not at all.

MR. ROACH: It has. Let me first of all attach to EPSA's comments, there is a legal analysis which I recommend. But let me speak as an economist or policymaker, again, in this second-best world.

Let me just say that I would not want to be a FERC Commissioner or FERC Staff on the day there's a real problem in any of the markets that you've mandated. I think the way the questioning would go if it was Congress or anyone, they would say, well, look. You required these short-term markets, didn't you? Yeah, we did. And what's the worst thing that could happen to a short-term market? A shortage. That's as bad as it gets.

Well, do you have a process in place that asks whether a shortage is imminent? If you said no to that, I think that would be a bad answer. And I view the resource adequacy requirement as asking, as a constructive way to ask that very responsible question of what's going on? Are we faced with a shortage anytime soon? Have we found it in time to react to do something about it?

MS. FERNANDEZ: Why don't I go down the line with Chairman Welch. Okay. Either of you can go first.

MR. NELSON: First of all, I agree with Craig that enforcement should be before real time and that the penalties should not await the end of the planning horizon.

But let me just say in response to the question that I think the final rule should, to the extent necessary, spell out some principles along the lines of what we've talked about today. But to harken back to somebody from a previous panel, I think this is an area that may not have to be fully developed as other parts of the SMD need to be when the final rule comes out.

I think a lot can be fleshed out afterwards, and I think the most significant thing for my purposes is that the final rule spell out a charge to the regional body, whatever that's called, to let them go ahead and develop these standards and work with the ITP in that regard.

MR. WELCH: A narrow point and a little broader one. The issue of focusing on penalty, and I think someone just correctly identified the difference. One is a sort of buy in advance and make sure you have it model, and the other was let's find the people who are guilty and zap them model.

I just think, and frankly what I've heard today reinforces that, that you can make a model that depends upon penalizing particular LSEs for a failure of foresight can ever be made consistent with a competitive retail market. So if you want a competitive retail market, I think you have to abandon that approach. It just doesn't work. I can't think of how to make it work. And if what's driving that is jurisdiction, it would be very frustrating, because going to Congress is always tricky. But I think that's preferable than killing the retail market, which is what would happen in my view under that.

But I think the broader question which you asked as to what should the order say, and I outlined some of the things before and the proposal outlines others, but I think there is a fundamental question for FERC to ask itself when it tries to make this decision, and that is, what is it -- I mean, if you see your responsibility as creating in the near term a nationwide market that will capture the benefits of the broad markets that FERC I think has correctly identified.

Then I think you do have to relatively soon, though perhaps with some transition periods for various regions, say that this is the system to which we will go. this is going to be the law of the land, and you should just deal with it. And the regions that are, you know, not as far advanced, although they would challenge the characterization of "advanced", I think need to begin to accommodate themselves to a system that does permit the kind of commodity flows that I think FERC has correctly identified as meeting the electricity market.

And that really goes to answering how much flexibility do you grant? And the question may be how much for how long? I think FERC ought to, with some areas better defined than others, but say these are the principles, these are the things that have to be achieved I think including something like resource adequacy, at least until that day in the future when demand elasticity is perfect, which I don't expect to live to see.

But really has to say we are going to get there, and here's something of a timetable, and here are the principles, and not simply say we'll just let things elsewhere go on indefinitely, if FERC believes that its role is to find for this country the best possible electricity market.

MR. KELLY: I wonder if instead of just going person by person if we might go principle by principle. Craig Roach proposed first that there be a resource adequacy requirement. I sense everyone here would agree with that.

A second principle is that enforcement should be before real time. But I'm not sure I heard everyone agree with that. Maybe we could focus on that a moment and then go to the next principle.

MS. FERNANDEZ: I think we have a disagreement.

MR. SUTCLIFFE: I have listened all day to the penalty discussions, and I think that it makes a lot of sense from a regulatory standpoint, it's sort of easy to administer. But the consequences of a penalty structure are that it kills the market for resource adequacy.

Let me explain. With the capital markets particularly today, if you are either a generating resource that is trying to obtain financing or you are a demand resource that depends upon capital to install either through lease or through an outsourcing basis in a customer's facility, you have to convince the funder that when you put this in, that you can confine and control the risks.

And there are certain risks that you have to take that you can't confine or control. Even if you put the penalty on the LSE, the LSE will immediately put it down on the resource supplier, okay. So it's really on the people who are trying to produce the product.

Well, you already have a penalty, because if you have laid plans to build a plant or to provide a distributed energy resource, you have failed in the marketplace. So you have a penalty, an economic penalty, already sitting there. But if you have on top of that a penalty, a huge penalty for deterrence, you'll never get the funding. Because the funder will say, well, we don't know -- how can you ensure against that risk?

Because you ensure it or you manage it one way or another, and that's a risk that you can't manage. And so you have to just accept the fact in a resource adequacy to take a little bit more resource in case there will be fallout. And that fallout can have nothing to do with the people who have advocated it. They have a clear site. Everything is going fine. They have their air permits, and they've bid it in and all of a sudden something changes. And it could be capital markets, it could be NIMB, it could be a number of different things.

And so the financial community that is backing the capital formation to do this thing, I don't think can tolerate the types of penalties that have been discussed. It might be very easy for FERC to administer, but I would suggest that the easier way is simply to say if you apply, if you have failed, you do not participate again. End of story. Or something that is not a management that will kill I believe a lot of the capital formation for the generation and for the distributed energy resource.

Does anybody else want to comment on enforcement before real time?

MR. SHANKER: Yes. I think I would disagree with that. And to be specific, in the context of the proposal we had put forward and I think that Dave went over this morning, there's at least two different types of penalty structures, and they need to be differentiated. The first is we hold the auction two or three years ahead and what do we do if there is a shortage, okay. And that has two forks in the road. If there is a demand curve, then we don't have a shortage, we just go out west because the demand curve says we're willing to accept the lower level of reliability at a higher unit price.

The second, which is the more common way people think about it is we have a vertical demand curve and someone says we want it 118 percent, we got it at 117 percent, the clearing price is at some deficiency level. That deficiency level is a penalty or whatever and it would be paid by any load that was unhedged and hadn't entered into a bilateral. It would be due at that time or it could be collected real time but it is a basically and in advance penalty and it occurs at a time that the market settles then, okay. That's the first penalty structure. We can argue about what it should be and what the inducement should be but basically the real goal is that it is high enough and we are far enough in the future that supply elasticity allows you to operate underneath that and we never have to invoke it. That's the good news.

The second penalty is, I have now sold myself into that market and we wander around and show up in real time and I don't deliver. And that's -- the first one is going to essentially be carried by load. The second one, and everything that occurs after that first auction is transfers among the suppliers. And we have talked about in the context of the JCAP proposal what would be pricing mechanisms for that second penalty. And I'll defer and there's a little write-up by Mike Head Wallater of LECG that goes through the logic, but basically a sound principle that was proposed was for that penalty in the real time failure to perform to be twice the clearing price of the original auction and that would be an inducement essentially for people to bid their expectations.

And if you work through it, you can see that a rational bidder with a reasonable probability on each side, whether how much he would deliver and what his risk would be, that kind of a penalty structure encourages him to bid exactly what he thinks he's going to be able to deliver. And in talking through this -- and this is how we get to Lynn's last point -- in talking through this with people, that didn't seem to be an unreasonable level of risk to bear. In fact, it would encourage them to bid the right amount so that the wouldn't face an unreasonable risk in performance.

MR. KELLY: Let me just note that it's the official closing time for the panel. We are prepared to stay and hear, I'd like to get a little more information about the principles that might be in any rule that would apply to all regions and if you're able to stay a little longer, panelists, we'd appreciate it. If any of you have planes to catch, please feel absolutely free to just stand up, go get your plane; don't worry about it, it's understood. But if you're able to stay a few minutes longer, we'd appreciate.

Alice, you were pursuing a line of questions on principles, did you want to pick that up again, or?

MS. FERNANDEZ: Well, I wasn't certain if I'd got answers from everyone, or if I was going to get answers from everyone. Let's sort of start at the end and I think, Mr. Sutcliffe?

MR. SUTCLIFFE: In answer to your question about what one might include in a rule, our experience is is that you need to have a reasonable mechanism for setting a price to which people can respond, so I would opt for the ITP with the RSAC substantially involved in establishing the price. What you're saying is you want an insurance policy and I would leave the level of that insurance policy payment to the not mandate a particular level but say you've got to set a level and you have to see what comes in terms of the response. And I would do this on a rolling basis. I wouldn't have an auction. I'd say here's a price, and when you fill up that, if you fill it up, fine; if you don't fill that up, then you offer some other incentives to fill it up, and you have to adjust everybody's price upwards.

We've seen this in the demand arena through standard offers and we've had tremendous response to that. And you get a time differentiation because some resources can come in quicker than others, and so you have this continuing rolling and moving thing, so I would opt for a fixed price established, here's the insurance policy, will you participate in this for that price, have the regions do that, and have the payment for the resource coincident with its resource needs. Because what becomes part of your resource adequacy for years two and three and four and five is your longer term meeting of need in years seven, eight, nine, and ten if it s a permanent resource. And you have to have someway to take that into account and to price it for the value that's being contributed in the particular market. So you sort of end of slipping back into some principles, IRP, least cost planning, etc., I don't know how you avoid it, but at least you can move it to another level, and that's what I would do if I had anything to do with it.

MR. VELAZAQUEZ: I wonder if I could just comment briefly? As I had said before, I think some of the key things EEI would like to see in the final rule first of all is this recognition that there are going to be some regional variances that are necessary and one size doesn't fit all. FERC does need to take a role, we think, in setting some guidelines under which this regional variation can occur, and I'd mentioned some of them earlier, you know, should be a forward obligation, there should be something to keep people from leaning on the others in the pool or in the market area, should be market-based, should be a level playing field for all resources, whether they're new, old, demand side, generation, whatever. It should very much have to be developed in conjunction with what you're doing on the market mitigation side on the energy markets that they're not an independent thing, can't be developed independently. And that penalties are not the preferred way to go if there is a market-based solution or some other way of doing it.

MR. GRAMLICH: Just to clarify, when you say market-based, you're not using that as a euphemism for the centralized capacity market which I think earlier you wouldn't have it, so market-based to you would mean what?

MR. VELAZAQUEZ: It was more thinking as we've talked about penalties and other issues sa are necessary as opposed to arbitrarily picking something that needs to be based on what's happening in the market and what's reasonable, you know, as far as other resources or alternatives are.

MR. SHANKER: I just didn't understand the answer. Are you advocating penalties or not?

MR. VELAZAQUEZ: I think at some point whatever however you come up with it, there is going to be some penalty mechanism for something and just saying that those should be based on kind of markets, and what the markets send signals for whatever you're establishing the penalty for.

MR. SHANKER: I think we use the notion of regional flexibility too loosely, and the rule has to be flexible. That's clear. And the reason some of it has to do with some regional differences but the real reason is is that there are so many other complementary details of how you do the rest of the market that it's almost impossible to be prescriptive of this one element without telling somebody all the other details.

This would interact with deliverability standards; this would interact with possible allocation schemes for FTRs.

This would interact with merchant transmission rights and property rights associated with expansion of the transmission system.

Flexibility, in my mind, means that when you give me all the rest of those -- and also retail rules as well, obviously -- that when you give me all those other conditions, I would come back and I would say I think you have put together a structure that will never work with any reasonable adequacy, or maybe if we tweak this and we tweak that, we can complement what's out there.

That's what I think is what you need to have in the rule, is the flexibility to adjust to all the different parameters that are in play. And I'm uncomfortable with the notion of regional diversity, because I'm not sure that that's what's underlying this, so much as that all the other -- in other parts of the company, people will choose among these other things, different paths that necessitate a different overall structure.

New York has a very different deliverability standard than PJM. Can they both work under the JCAG structure? The answer is yes.

One of the proposals that I plan on doing next is, there's actually a way to have an integrated auction with locational characteristics across the whole region, that would likely allow an integrated adequacy tool, without necessarily -- or product -- without necessarily having to have an integrated energy market.

But you can only do that under some very specific conditions about other property rights in the region, about how CRRs are going to work, how expansion rights are going to work, how people deal with the actual topology of the grid that they use for their reliability planning. All of those things come into play when you get down to really turning the fine crank.

So I guess what I want to see is you be flexible enough to allow that, and at the same time, I don't want it to be so flexible that someone can up with something that's a lousy solution.

MS. FERNANDEZ: I guess to follow up on that, if someone -- let's say that the regional variation was that there was a requirement to meet a -- there be some reliability required, based on some probabalistic number that was determined as the appropriate one for the region.

And that based on the resources within the region

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MR. KELLY: I note that Chairman Welch has to catch a plane. If you care to, would you want to either recap or state any principles, as you're running for the plane?

(Laughter.)

MR. WELCH: It's a hard invitation to resist. I think I stated them sort of at the beginning, but I think that the -- with respect to capacity adequacy, it has to be a system that produces enough money to create the resources you want, does it in a way that does not interfere with the retail markets, and, therefore, I think, really needs to be something like a central capacity acquisition scheme, as opposed to a penalty scheme that depends on particular LESs' responsibilities.

And I think that beyond that, it needs to -- there -- it needs to be clear that FERC will insist upon some efficient ways of identifying the price and minimizing estimation error.

So you can develop a model that's 20 years out, but you'd have a vast estimation error. One year out, you don't get what you need. There may be some kinds of auctions that work better than others, sort of the Dutch auction that's been described, and there may be others.

I think those are ones where you probably don't have to decide right now, but I think deciding fundamentally that this is something that's being done for the market as a whole, rather than to test whether any particular LSE has good foresight or good morals, is probably the fundamental principle from which most other things derive.

MR. KELLY: Thank you.

MR. WELCH: Thank you. Sorry to leave.

MR. KELLY: Have a good flight. Mr. Shanker, sorry for the interruption.

MS. FERNANDEZ: I guess I was trying to figure out, in terms of the market mitigation, it seems like something that's been mentioned frequently, would need to change. Is that -- I mean, if you had a system where, say, there was an overall requirement to meet the reliability, but there was no type of centralized market or no type of capacity market; it was more an obligation to meet the requirement and then there would be some penalty, if it had not been met, what other changes would you sort of need in the overall package?

It seems that the overall market mitigation is something that's been talked about.

MR. SHANKER: Well, that process, per se, I have a lot of problems with, unless the unit of LSE is a control area. Then I can see it kind of working, because now it's visible.

I can do load shed. I can penalize someone real-time. I can deny them power.

Okay, I'm not sure you want to foster that system, but is it feasible to do that? Yes, it is.

So that's an example of if you tell me there's not going to be retail access and you tell me that there's not going to be significant divestiture, could we work it the way you have proposed it? And the answer is yes.

I, personally don't think that's a really good way to go, because I think it still doesn't deal with the supply elasticity questions. It sort of all gets -- it sort of still tempts people into the free-riding behavior, and then you're going to have to come up with a penalty structure that discourages that.

But could you implement it, you know, if you're willing to look at $10,000 and $20,000 penalties for that kind of behavior, which is what the numbers -- you know, I do back-of-the-envelope, I get $10,000 or $20,000 -- studies are in that same range. You know, Mark Younger did some numbers for New York.

You always come up with numbers like this. If you want to have a system that says roll the dice and every now and then the people who are free riders face $10,000 or $20,000 a megawatt hour prices, that's fine.

I don't know that that's what you wanted. I sort of thought that you wanted to kill that kind of volatility and make things more predictable and more reliable. If that's what you want to do, then we go another path.

MS. FERNANDEZ: I guess I was trying to explore sort of what -- if you wanted to go down that option, what would be the consequences.

MR. SHANKER: Well, one, you're still going to see volatility. You're going to encourage free riding, you're not necessarily going to get, unless the penalties are high enough, you're not necessarily going to get bilaterals that support new entry.

You know, what will happen is, you'll go along and then the system collapses, and there will be a mess, and then all the free riders start whining, and look for a regulatory bailout, and will have a test about whether or not you're willing to stand up for a system that you designed to have a result with very, very high prices. One way or another, it's going to happen that way, and it seems antithetical to me that the reason we're doing this is because we started off with an unwillingness to tolerate that kind of volatility.

MR. KELLY: Just a comment: I think you're taking the states out of your analysis, and they're not players in the way you described the scenario. We were recognizing the fact that most states have, historically, and continue to impose some sort of resource adequacy requirement. And we didn't want to override that with a federal mandate.

The states are capable of regulating either monopoly-integrated utilities or -- Chairman Welch left too soon -- I think energy service suppliers, who are licensed to do business in the states, either as they have historically regulated utilities, saying you must meet a requirement, so that the penalty is just kind of lying out there as a threat, or with the energy service supplier to say, as you'd say to an insurance company, if you're going to do business in our state, you need to have deep enough pockets to be insured against a contingency that you occasionally will have to pay this high penalty, because you're not passing it through.

MR. SHANKER: If you assume there's state regulation that's going to override the penalty -- not the penalty, but set a mandate, then we're fine again, because you've resolved the problem.

MR. KELLY: And we're not only assuming that, if we didn't assume that, I think we have an even bigger political problem in non-retail, especially in non-retail access states, of, by federal action, taking the states out of the picture.

A difficulty with what you proposed, if we do it nationally, is, I think it would take states completely out of the picture, and I think that's a problem we'd have to address.

MR. SHANKER: I don't want to monopolize this, but one thing that hasn't come up -- and I don't know if there is anybody here that's more familiar with it -- there is a memorandum of understanding among the state regulators for PJM, and that has served as an umbrella under which all of the stuff we are talking about has gone on.

And everybody, as far as I can tell, seems to be happy, at least at the state regulatory level, with the conduct of the reliability assurance agreements, the standards that have come out of this, the one day in ten.

They obviously aren't necessarily happy with the volatility and the market power issues in the market, but in terms of the delegation of authority, the establishment of targets, the installed requirements and things like that, there seems to have been a consensus process.

So, I'm not so sure, even in the process we're talking about for the Northeast, that the states have been taken out. They've gotten a parallel process, that they have had their say, and seemed to be content with the process as it's going.

MR. KELLY: We have indulged on your time quite a bit. I'd like to take the two remaining cards that are up, and if any card goes up in the next ten seconds, you'll be added to the list, and then we'll conclude the panel after that.

I will go to Rich Campbell first. It's been awhile since you've had a chance to talk.

MR. CAMPBELL: Well, what I wanted to say was, I do believe we do have to have more flexibility as far as resource planing for the states involved concerning the level of reliability and the variability in the resources that each state has at its disposal.

But I also want to say that there should be some consideration to changes in technology. I think the SMD vision has a limited horizon, a short- to medium-term horizon that doesn't look at what could happen, say, with technology, with, say, fuel cells or other technologies that may make improvements to the transmission structure or distribution structure not necessary.

If we could use better -- make better use of existing resources, as Ed was suggesting, with the backup generation that industrials have, or looking at different ways to utilize the existing transmission and distribution system and make it much more efficient.

MR. KELLY: Thank you. Craig Roach, you have the last word.

MR. ROACH: Thank you. Just very quickly, I was -- the notion of regional variation, I think the key is to decide what can have regional variation and what can't. I really think you want to decide the penalty versus market enforcement. That's a big one.

But, for example, you know, once you get in, say, you choose the market side, I think there are lots of mechanics out there, even I think it's a very legitimate issue that Lynn and Roy are raisin about new entrants in demand-side, for example.

But there are lots of mechanics that take care of that. You don't have to make this universal decision on doing everything three years ahead, or doing it in real-time.

One of your questions uses the word, ladder, which is a good mechanic. It says, okay, look, we expect demand side to be about four percent of the market, and we want -- we're concerned, so let's set -- several years ahead, let's set 85 percent or 90 percent of the resource requirement and leave some flexibility there.

So I'm just saying that there are certain things you have to decide what you have to decide, and there are a lot of mechanics that you will see that address some issues where you don't have to make major choices.

MR. KELLY: I want to thank all of you for coming today. I know many of you have very busy schedules, and it means a lot to us that you took time out of them to come and help us sort through these very difficult issues. We appreciate it, and the panel is concluded, and the day is concluded. Thank you.

(Whereupon, at 5:32 p.m., the technical conference was concluded.)